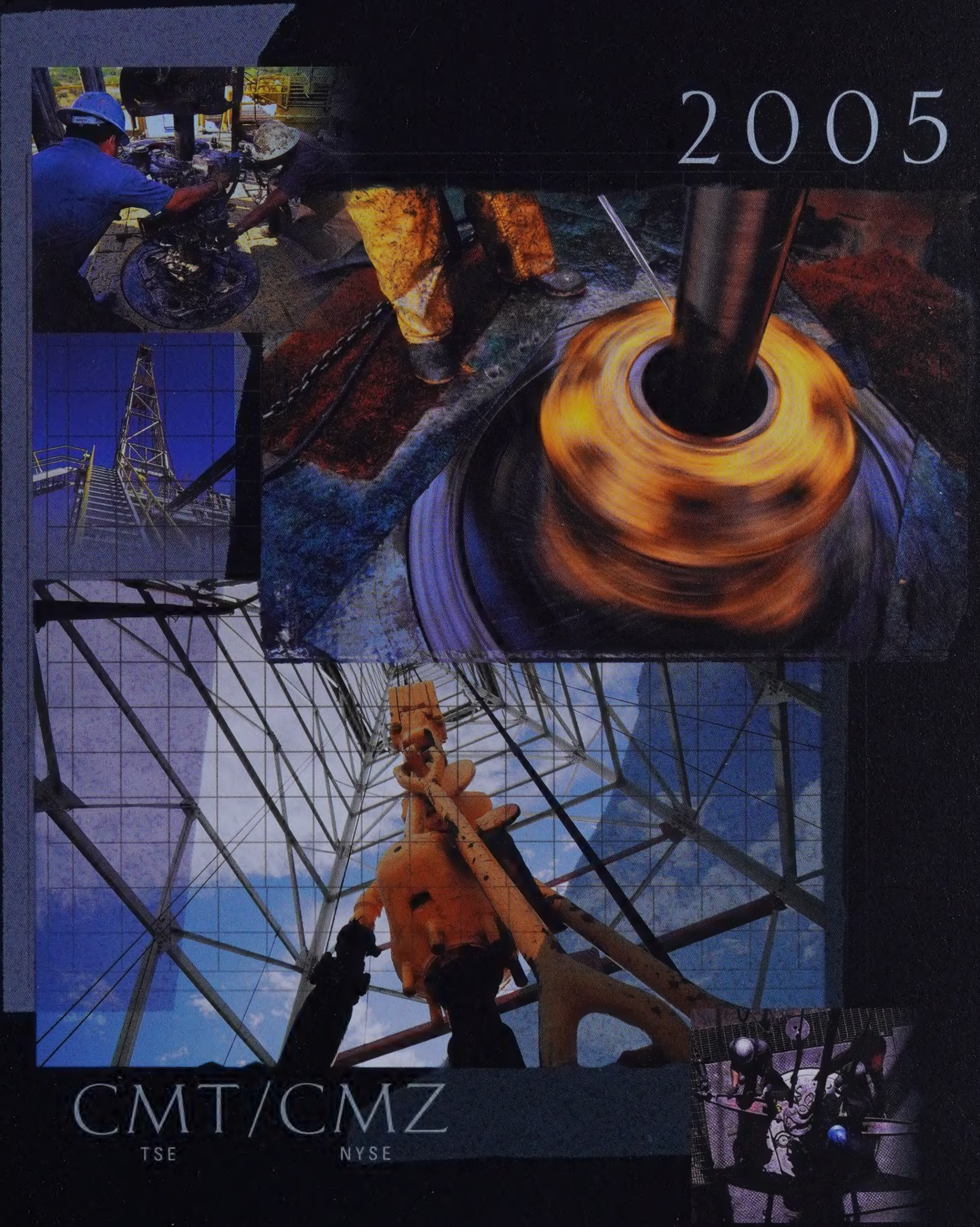
COMPTON

COMPTON PETROLEUM CORPORATION · ANNUAL REPORT 2005

2005



CMT/CMZ

TSE NYSE

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ANNUAL MEETING INFORMATION

The Annual General Meeting of Shareholders will be held on Wednesday, May 10, 2006 at 3:30 p.m. in the Historical Ballroom of the Calgary Chamber of Commerce, 17 - Centre Street South, Calgary, Alberta, Canada.

CMT/CMZ

TSE NYSE

CORPORATE PROFILE

Compton Petroleum Corporation is a Calgary based public company actively engaged in the exploration, development, and production of natural gas, natural gas liquids, and crude oil in the Western Canada Sedimentary Basin. Compton's shares are listed on the Toronto Stock Exchange under the symbol CMT and on the New York Stock Exchange under the symbol CMZ.

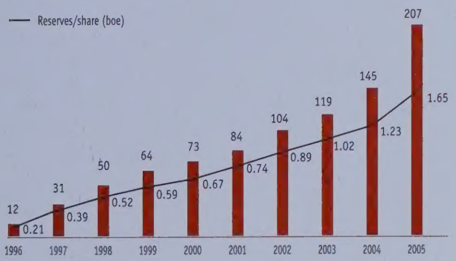
Financial Highlights

($000s, except where noted)	2005	2004	2003
Total revenue	**$ 557,879**	$ 391,659	$ 346,565
Cash flow from operations	**$ 278,112**	$ 177,131	$ 154,893
Per share: basic ($)	**$ 2.21**	$ 1.51	$ 1.33
diluted ($)	**$ 2.11**	$ 1.43	$ 1.27
Net earnings	**$ 81,326**	$ 63,633	$ 118,880
Per share: basic ($)	**$ 0.65**	$ 0.54	$ 1.02
diluted ($)	**$ 0.62**	$ 0.51	$ 0.97
Capital expenditures	**$ 513,536**	$ 316,401	$ 285,483
Corporate debt, net	**$ 601,121**	$ 417,212	$ 355,903
Shareholders' equity	**$ 596,336**	$ 424,078	$ 356,906
Share Price			
High	**$ 18.66**	$ 11.43	$ 6.35
Low	**$ 9.80**	$ 5.89	$ 4.40
Close	**$ 17.10**	$ 10.85	$ 6.00
Average volume traded	**736,416**	674,764	686,100

Operational Highlights

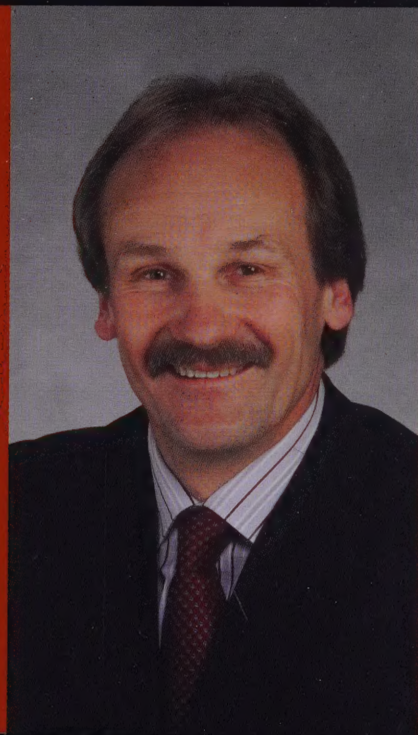
Average daily production volumes			
Natural gas (MMcf/d)	**131**	123	118
Liquids (light oil & ngls) (bbls/d)	**7,646**	6,330	5,924
Total oil equivalent (boe/d)	**29,424**	26,876	25,552
Average pricing			
Natural gas (per Mcf)	**$ 8.42**	$ 6.46	$ 6.27
Liquids ($/bbl)	**$ 56.04**	$ 43.21	$ 35.59
Total oil equivalent ($/boe)	**$ 51.95**	$ 39.82	$ 37.16
Field operating netback ($/boe)	**$ 32.36**	$ 23.79	$ 22.05
Cash flow netback ($/boe)	**$ 26.66**	$ 18.53	$ 17.11
Undeveloped land			
Gross acres	**971,317**	1,019,854	1,042,802
Net acres	**738,954**	729,429	767,364
Average working interest	**76%**	72%	74%
Reserves			
Proved (Mboe)	**125,960**	96,805	84,627
Proved + probable (Mboe)	**206,672**	144,777	118,763
Reserve life index (P+P)	**19**	15	13

Reserve Growth
Proved + Probable (mmboe) (6:1)



** 1996-2002 Established reserves (proved + risked probable)*

Share Price Performance
as at December 31 ($/share)



Ernie Sapieha,
President & Chief Executive Officer

Despite challenging times in the oil and gas industry, we are excited and optimistic about the opportunities that lie ahead for Compton.

2005 President's Message

For Compton, 2005 was an outstanding year. Our accelerated drilling program generated record cash flow, significant reserve growth, production increases, and confirmed our tremendous resource potential. We remain focused on delivering strong shareholder value and have realized a 37% compound annual growth rate in equity value since we first went public nine years ago. We believe that the five resource plays we have developed will continue to add significant shareholder value for years to come. I am exceptionally proud of the hard work and accomplishments delivered by Compton's team this year in an extremely difficult and competitive operating environment.

2005 ACCOMPLISHMENTS

Highlights of our 2005 achievements include:

Reserves

- Drill bit reserve additions of 62 MMboe, a 43% increase over last year
- Identification of 15+ Tcf unrisked resource potential
- Top quartile finding and development (F&D) costs of $7.05 per boe on a proved plus probable basis, excluding future capital
- 676% production replacement
- Proved reserve life index of 12 years

Operating

- Drilled 392 wells, more than twice the number of wells drilled in 2004
- Drilled 115 wells and completed 161 tie-ins in the fourth quarter
- 2005 production increased nearly 10%
- Completed a $512 million capital expenditure program
- Achieved operating cash flow of $278 million

Financial

- Cash flow per share up 46% to $2.21
- Operating earnings up 98% to $0.79 per share
- Oversubscribed $90 million equity offering
- Issuance of U.S.$300 million $7^{5}/8\%$ Senior Notes
- New York Stock Exchange (NYSE) listing
- Market capitalization greater than $2 billion
- Net asset value in excess of $20 per share versus a December 31, 2005 share price of $17.10

In 2005, we accelerated our drilling program, generated record cash flow, achieved significant reserve growth and production increases, and confirmed our tremendous resource potential.

Compton's Executive and Directors ringing the opening bell at the NYSE

RESOURCE PLAYS

- Completed extensive CBM resource evaluations, confirming 3.05 Tcf (2.75 Tcf net) of unrisked gas-in-place on approximately 760 (680 net) sections, or three-quarters of Compton's Southern Alberta land. Evaluation of the remaining additional 275 (250 net) sections is ongoing.
- Drilled 170 successful Plains Belly River wells, improving and further refining our technical models. 3,000+ locations for future drilling have been identified.

- The perimeters of the Hooker play, where we drilled 27 successful wells this year, have continued to expand and have yet to be determined. In the second half of 2006, commencement of the Company's Hooker pilot of three wells per section spacing will be undertaken to accelerate production and reserve recognition, as well as extend the productive limits of this play.
- Significant advances in our understanding of Callum's complex reservoir were achieved this year, and we are well on our way to realizing this play's 80+ Bcf per section gas-in-place potential.
- Results and reserves from the 33 wells drilled at Niton this year continue to exceed expectations and expand our resource potential and, as a result, we are aggressively expanding facility and land holdings in this area.

Following two years of resource play delineation in 2003 and 2004, Compton became one of the top 10 most active drilling operators in Canada in 2005. A fundamental of our corporate strategy is to deliver superior growth through the drill bit, and in 2005, we've done exactly that while still remaining in the industry's top quartile for low finding and development costs. We drilled 392 wells in 2005, more than twice the number we drilled in the previous year. Excellent progress was made on all five of our resource plays, and Compton has more than 10 years of drilling opportunities.

Compton's 2005 drilling program delivered 29 million boe proved and 62 million boe proved plus probable reserve adds, for total proved plus probable reserves of 207 million boe as at December 31, 2005.

Compton's 2005 drilling program delivered 29 million boe proved and 62 million boe proved plus probable reserve adds, for total proved plus probable reserves of 207 million boe as at December 31, 2005. This represents a 30% and 43% increase over our 2004 proved and proved plus probable reserves, respectively, and a 27% compound annual growth rate since our first reserve report in 1996. Our reserve growth translates into 1.65 boe per common share outstanding versus 1.23 boe per share at year end 2004. Using an eight percent discounted cash flow, the reserves alone have been valued at $2.8 billion, and in 2006 our technical teams will continue evaluations of our possible reserves with the view to increasing our resource value further. Compton's reserves are solid, long life cash flow generators, and importantly, we have never had a material reserve revision.

In 2005, we completed an extensive CBM resource evaluation and four coal bed methane pilot projects targeting the Edmonton Horseshoe Canyon Coals on approximately 75% of Compton's Southern Alberta lands. As a result of these projects and other initiatives, Netherland, Sewell & Associates, Inc., independent reserve evaluators, have estimated 3.05 Tcf (2.75 Tcf net) of unrisked gas-in-place from the Horseshoe Canyon Coals, excluding the sands, silts, and shales of the Edmonton formation. A lack of production history from the coals has prevented us from recording any significant CBM reserves at year end 2005, with the exception of 10 Bcf attributable to Ghost Pine. We believe that for 2006, CBM production, completion of our two remaining pilot projects, and an aggressive workover program on our existing Belly River producers will be critical and beneficial in the determination of recovery factors and material reserve adds from the Horseshoe Canyon zone. We are both confident in and optimistic about the potential of our CBM resource play.

2005 at Callum was characterized as a year of extensive research, rock work, analysis of cores, completion programs, seismic modelling, and technical and landholder consultation, while only one well was drilled. We are encouraged by our rock work and the recent completion of this well. The first two weeks of initial production averaged approximately 1,525 boe per day (7.6 MMcf per day, plus 260 barrels per day of associated liquids) from a single sand. This well paid out in 48 days, and was still producing approximately 300 boe per day at the end of February 2006, better than our model expectations. The key for us now is further success from additional wells and workovers of existing wells. Looking forward to the potential inherent in this play, we plan to drill 10 wells at Callum in 2006 and further test our models.

Compton experienced excellent results in both the Plains Belly River and at Niton. In the Belly River, we drilled 170 wells, with a 100% success rate, and we are planning to drill another 250 wells here in 2006. We also have 70 Belly River wells scheduled for uphole CBM recompletion next year. We have extensive 2D and 3D seismic over our Central and Southern Alberta lands and this, combined with the precision of our geological and engineering models, continues to produce outstanding results. In Central Alberta, we drilled 73 wells with a 97% success rate in 2005. Thirty-three of these wells were drilled at Niton, and results continue to exceed expectations. In 2006, we will drill 90 wells in this area, as well as focus on expanding our facility and land holdings.

Compton drilled 123 wells in the Peace River Arch in 2005, and we plan to drill another 106 next year. Our drilling results at Worsley and Cecil continue to be very good, generally encountering multiple pay zones.

INDUSTRY CHALLENGES

We are excited and optimistic about the opportunities that lie ahead for Compton, even though it is a challenging time in the oil and gas industry. Higher commodity prices have accelerated capital programs and capital availability, and this has, in turn, created industry wide service and supply shortages. Although Compton had excellent drilling results and reserve adds during the year, we did encounter production challenges. The majority of the Company's operations are located in Southern and Central Alberta, areas that experienced an early break-up in February, followed by abnormally high precipitation levels and flooding during the summer months. Well completions, pipeline construction, and tie-ins were interrupted and delayed. However, Compton's large inventory of drill locations afforded us the opportunity to mitigate the impact of adverse weather conditions by redeploying resources to our properties in the Peace River Arch.

The foundations of Compton's successful growth strategy are the Company's extensive land base, focused activity in our low risk core areas, control of infrastructure and operatorship, and our experienced, dedicated technical teams.

Land prices in Compton's core areas have also escalated, recently selling for more than $1,000 per acre for large blocks of CBM rights alone in Southern Alberta. Importantly, the Company currently holds more than a million net acres of largely contiguous land, a competitive advantage that would be difficult to replicate given current prices and industry competition. At existing prices, we estimate our undeveloped land holdings are worth $3 to $4 per share.

More recently, we've seen a downturn in commodity prices. However, Compton's capital structure and hedging program are specifically designed to mitigate the cyclical risks of this industry. In February, we issued $90 million of additional equity. The offering was oversubscribed, and the proceeds were used to fund drilling. We also redeemed the Company's 9.90% U.S.$165 million notes and issued U.S.$300 million of 7⁵/8% Senior Notes due in 2013. Then, in December, our shares began trading on the New York Stock Exchange. This broadening of our shareholder base combined with the equity addition and debt refinancing has enhanced our financial flexibility, ensuring Compton has a healthy and competitive balance sheet heading into 2006 to fund its growth activities. With our high quality, long-life reserves and production profile, Compton is comfortable operating at a debt to cash flow ratio of 2:1.

WHY INVEST IN COMPTON?

The foundations of Compton's successful growth strategy are the Company's extensive land base, focused activity in our low risk core areas, control of infrastructure and operatorship, and our experienced, dedicated technical teams. Very few of our peers can show a greater than 90% growth rate through the drill bit for the past five years. It is this growth that continues to bolster Compton's net asset value and create shareholder wealth.

The risk associated with the CBM, Belly River, Hooker, and Niton resource plays continues to decline as these plays move further into the development stage. Compton had 1.2 Tcf of proved plus probable reserves booked at December 31, 2005. Yet, based upon our internal evaluations, we believe the net unrisked resource potential of our lands is in excess of 15 Tcf. Compton believes these plays have significant upside, and we will remain focused on unlocking this potential in 2006 and beyond.

Well downspacing will be key in the development of Compton's unconventional gas resources in years to come. Early in 2006, the Alberta Energy and Utilities Board announced an initiative to modify its baseline gas well spacing over an area that encompasses Compton's Southern Alberta land base. The new regulations are intended to change standard spacing from one well per section to four wells per section for shallow zones such as the Plains Belly River and Edmonton sands, and to two wells per section for Mannville targets such as the Basal Quartz formation. The EUB expects to implement these changes in the summer of 2006.

The Company's overall objectives for 2006 are consistent and clear: continue the development of our resource plays and conventional light oil property through the drill bit and maximize reserve recognition and value.

2006

The Company's overall objectives for 2006 are consistent and clear: continue the development of our resource plays and conventional light oil property through the drill bit and maximize reserve recognition and value. To this end, we've planned a $575 million capital program to fund an aggressive year of drilling 480 wells. We have targeted a 20% production growth rate for 2006, and we believe that with downspacing and increased well counts, 2007 could be even more exceptional.

The necessary elements are in place for Compton to achieve superior results and deliver significant value for shareholders. We have a vast land position across our core areas, with a 10 year inventory of drilling locations. The risk profile of our plays is decreasing as we refine our models and move further into the development phase of the plays.

The most important part of any business is creative people with great ideas combined with passion, dedication, and enthusiasm. One of Compton's greatest strengths has always been our innovative people and the Compton culture they have created. More than ever, our skilled and dedicated teams are crucial to the success of the Company. I wish to thank all of Compton's employees for the passion and commitment they bring to work each day. I would also like to thank Kim Davies, VP of New Ventures, for her efforts and contributions. After nine years with Compton, Kim retired in January 2006 to pursue other activities. We wish Kim the best of luck.

Finally, I would also like to thank our Board of Directors for their steadfast guidance, support, and enthusiasm.

Sincerely,

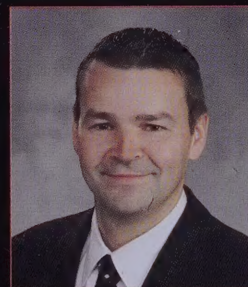
ERNIE SAPIEHA
President & Chief Executive Officer

We wish to thank all of Compton's employees for the passion and commitment they bring to work each day.

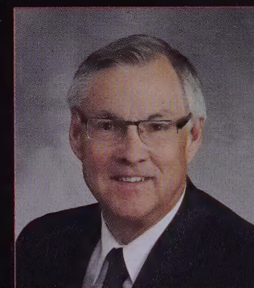
The most important part of any business is creative people with great ideas combined with passion, dedication, and enthusiasm. One of Compton's greatest strengths has always been our innovative people and the Compton culture they have created. More than ever, our skilled and dedicated teams are crucial to the success of the Company.

William Cover,
Manager, Drilling & Completions

Kim Davies,
VP New Ventures

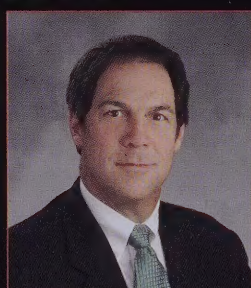


Robert Dion,
Manager, Finance

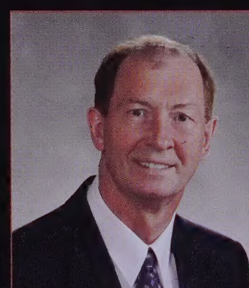


Gary Follensbee,
Manager, Mazeppa Operations

George Fukushima,
Manager, Reserves



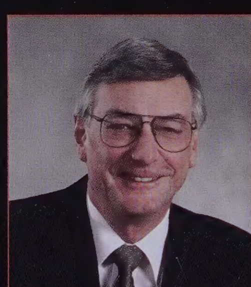
Ron Gerlitz,
Manager, Acquisitions & Divestments



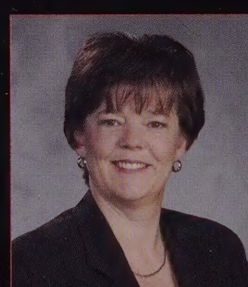
Richard Joy,
Manager, Exploration Central

Marc Junghans,
VP Exploration

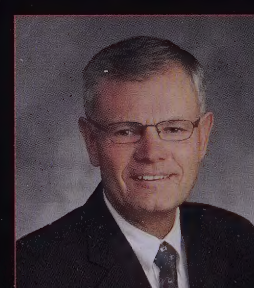
Corinna King,
Manager, Investor Relations



Norm Knecht,
VP Finance & C.F.O.



Theresa Kosek,
Accounting Manager



Bill Leonard,
Manager, Human Resources

Derek Longfield,
VP Special Projects

Bill McCloskey,
Manager, Exploration South

Garry McCullough,
Land Manager

Tim Millar,
VP, General Counsel & Corporate Secretary

Wade Mrochuk,
Production Manager

Paul Parzen,
Manager, IT, Risk & Internal Audit

Ernie Sapieha,
President & C.E.O.

Murray Stodalka,
VP Operations & Engineering

Doug Voegtlin,
Manager, Geophysics

Pary Weiler,
Manager, Surface Land

Bob Wilson,
Manager, Engineering North

Stan Wolny,
Manager, Engineering South

The Company had a successful drilling program in 2005, with progress made on all five resource plays. Compton was one of the top 10 most active operators in Canada throughout the year, drilling 392 wells with a 96% success rate. The Company completed its drilling program, resulting in 62 MMboe of reserve adds, despite flooding and abnormally high levels of rain throughout the summer in Southern Alberta. In 2006, Compton plans to drill 480 wells, continuing to focus on maximizing production and reserve growth in all core areas.

Property Review

Compton engages in oil and gas exploration and development in the Western Canada Sedimentary Basin of Alberta, Canada. Core areas range from unconventional prospects in the deep basin area of Southern and Central Alberta to conventional oil and gas prospects in the Peace River Arch region of northwestern Alberta. The Company is focused on five resource plays, including the Hooker Basal Quartz sands, multi-zone Plains Belly River, Edmonton Horseshoe Canyon coalbed methane ("CBM"), the stacked, thrusted Foothills Upper Cretaceous Belly River play at Callum, as well as the Gething/Rock Creek sands at Niton in Central Alberta.

The Company had a successful drilling program in 2005, with progress made on all five resource plays. Compton was one of the top 10 most active operators in Canada throughout the year, drilling 392 wells with a 96% success rate. The Company completed its drilling program, resulting in 62 MMboe of reserve adds, despite flooding and abnormally high levels of rain throughout the summer in Southern Alberta. In 2006, Compton plans to drill 480 wells, continuing to focus on maximizing production and reserve growth in all core areas.

Production
(Mboe/day)

SOUTHERN ALBERTA

Southern Alberta remains the primary focus of Compton's activities. The Company holds 804,007 (699,751 net) acres of land in the South, which are prospective for multiple zones including Basal Quartz at Hooker, thrusted Belly River at Callum, Wabamun/Crossfield, Plains Belly River, and Edmonton/CBM. In 2005, Compton drilled 195 (183 net) wells in Southern Alberta with a 99% success rate. The Company anticipates spending $361 million and drilling 277 wells in the area in 2006.

Hooker Basal Quartz

During the past year, Compton continued the development of its Lower Cretaceous Basal Quartz resource play at Hooker. The play covers an extensive area of 260,270 (195,200 net) acres. In 2005, the Company drilled 27 wells, extending the productive limits and optimizing reserve recovery in the heart of the pool.

In 2005, Compton designed and completed several advanced core and log analysis studies to gain a better understanding of the petrophysical characteristics of the play. As a result of this work, the Company now estimates that the Hooker pool contains at least 1.5 Tcf of gas-in-place. Compton is currently conducting further engineering and geological studies to confirm its expectations that the gas-in-place may be greater than initially determined. It has also become evident that the edges of the Hooker pool are not yet clearly identified and as such, Compton has designed its 2006 drilling program to infill and extend the productive limits of the pool.

The Hooker play is currently drilled on one to two wells per section, however, engineering models and geological studies indicate that at least three wells per section will be required to maximize reserve recovery from this low permeability gas pool. Compton has made an application to the EUB to conduct a pilot drilling program on two sections in the pool to evaluate the effectiveness of reduced spacing.

Plains Belly River and Horseshoe Canyon Coalbed Methane

In 2005, the Company drilled 170 Belly River wells in the Centron, Gladys, and Brant areas, with all wells encountering multiple pay sections and uphole producible Edmonton/Horseshoe Canyon Coals. The Belly River drilling program continues to exceed expectations.

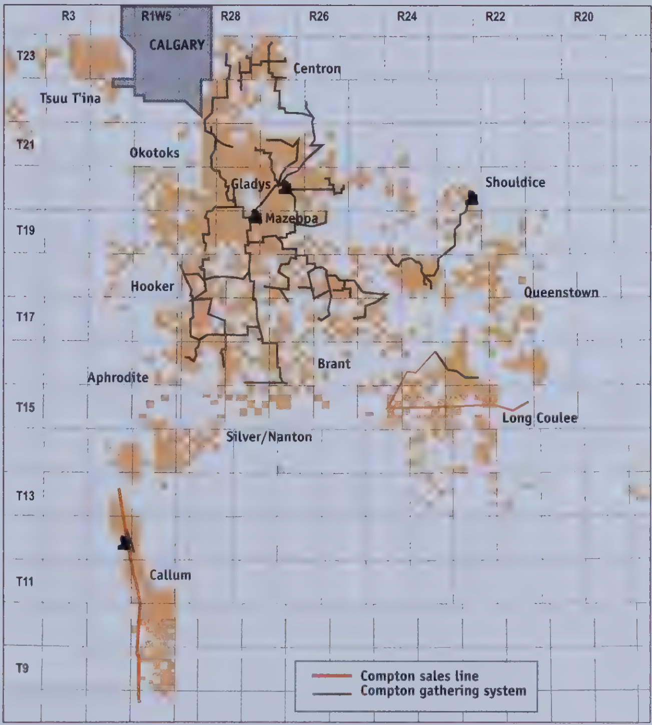
Compton further refined its Belly River seismic and geological models during the year. The use of the Company's extensive 3D and 2D seismic database was critical to identifying the best producible sands. The models were tested and confirmed through drilling.

Compton currently has approval to drill two wells per section on seven townships of land. The Alberta Energy and Utilities Board recently announced a phased modification to spacing for the Belly River in Southern Alberta that is intended to see the standard spacing change from one well per section to four wells per section. This initiative would effectively double the number of Belly River drilling locations in the Company's inventory. In anticipation of reduced spacing approval, Compton initiated three 3D seismic programs to assist in the identification of downspace locations. Drilling in select areas on reduced spacing is expected to start during the third quarter of 2006. This will allow Compton to dramatically ramp up its Belly River/Edmonton drilling program, commencing in 2007.

Compton will also define the optimum development of the vertical section of Belly River and Edmonton Horseshoe Canyon zones. The Company plans to drill 250 wells in 2006 that will have the potential to be completed in both zones. In addition, Compton has drilled over 400 wells through the Edmonton Horseshoe Canyon formation into the Belly River sands and the Company is planning to re-complete 70 wells in the Edmonton in 2006.

Compton holds 664,175 (597,760 net) acres of land in Southern Alberta that is prospective for dry Edmonton Horseshoe Canyon coalbed methane and the underlying Plains Belly River sands. During 2005, Compton drilled and cored four CBM pilots across its Southern Alberta acreage to gather the necessary geological evidence to better quantify its CBM resource potential. Each pilot consisted of four to six wells, for a total of 19 wells drilled. In-line flow testing on the initial pilots commenced in the first quarter of 2006 and two additional pilots are in various stages of well licensing.

The pilots assessed the potential of 483,560 (435,200 net) acres of the Company's lands in the South. Compton worked closely with Netherland, Sewell & Associates, Inc., ("Netherland Sewell") independent reserve evaluators, throughout the pilot programs to quantify the resource potential associated with the Horseshoe Canyon coals. Netherland Sewell has determined the original unrisked gas-in-place in the Horseshoe Canyon coals to be 3.05 Tcf and Compton estimates the net original unrisked gas-in-place on the Company's acreage to be 2.7 Tcf. This gas-in-place number is restricted to the coals only, with no interbedded Edmonton sands, silts, or shales included. Additionally, the pilot evaluations excluded any potential gas that may be present in the overlying Scollard Formation.



As confirmed by well logs, the remaining 177,780 (160,000 net) acres of Compton's acreage contain Edmonton sands, silts, and thinner Horseshoe Canyon coals, and will require further core confirmation of the gas content. In 2006, Compton will evaluate and quantify the potential of the Edmonton sands and silts across the Company's acreage.

The Company has production from the Edmonton Horseshoe Canyon coals at Centron, Gladys, Brant, and Ghost Pine. Currently Belly River production extends across Compton's Southern Alberta lands.

Callum Thrusted Belly River

The Callum property consists of a series of low permeability, overpressured, thrusted Upper Cretaceous Belly River sands in the foothills of Southern Alberta. Subsequent to year end, the Company acquired its partner's working interest in the play and now holds a 100% interest in 70,400 acres of land.

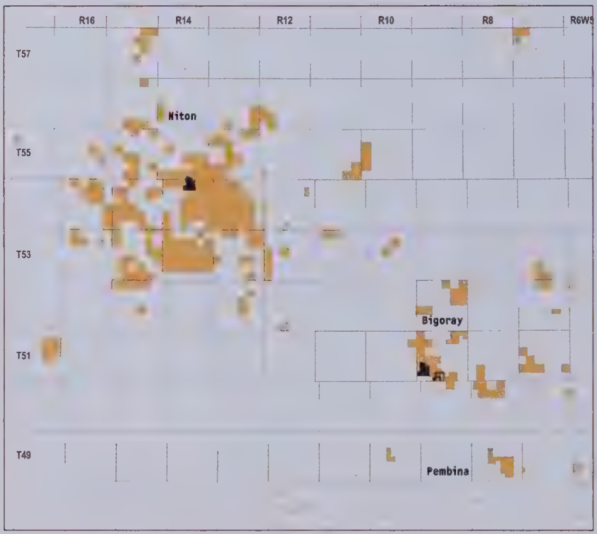
In the second quarter of 2005, the Company drilled a 100% working interest natural gas well at Callum. Specialized core analysis techniques were used to assist in identifying more prospective intervals and to optimize completion fluids and frac design parameters. The lowermost sand in the stacked Belly River sequence was completed in this well and Compton plans to

monitor and analyze this single zone performance before completing prospective uphole zones. The well was placed on continuous production in December 2005. The first two weeks of initial production averaged approximately 1,525 boe per day from a single sand and the well is continuing to produce approximately 300 boe per day as at the end of February 2006. This well has significantly improved the Company's geological, geophysical, and engineering models of the play. The resultant advances in the understanding of this complex reservoir are a major step forward in the development of the Callum play.

The play is technically complex and the key to successfully developing the Callum prospect rests with rock characterization and completion optimization. In the eight Compton wells drilled to date, various completion techniques have been evaluated. All wells have produced gas and initial production ranged from 300 Mcfe/d to 8 MMcfe/d.

A second well was drilled in December 2005, encountering multiple sands. The well has since been cased and Compton is currently testing. The second well will be completed using methods pioneered by Compton on its previous well. In 2006, 10 wells are planned at Callum.

Based on Compton's initial detailed geological, geophysical, and engineering analysis of seismic, cores, well logs, test and production data, Callum appears to exhibit many similarities to the deep unconventional gas pools of the Rocky Mountain region of the United States, specifically in the Greater Green River Basin in Wyoming.



CENTRAL ALBERTA

Central Alberta provides Compton with excellent exploration and development drilling opportunities using analogous techniques gained through its years of experience in Southern Alberta unconventional gas development. Compton has an average 55% working interest in 541,643 (297,475 net) acres of land. In 2005, the Company drilled 73 (38 net) wells with a 97% success rate and plans to drill 90 wells in the area in 2006.

Niton

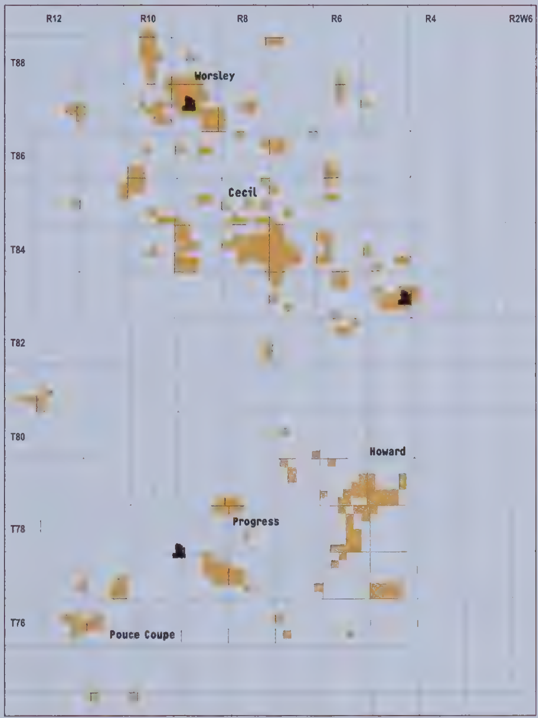
The Niton area, where the majority of Compton's Central Alberta acreage lies, is characterized by multi-zone, deep basin targets analogous to the Hooker pool in Southern Alberta. The Company has an interest in 137,390 (103,040 net) acres of land in the play targeting the Gething and Rock Creek formations. In 2005, 33 wells were drilled and results have continued to exceed expectations.

As a result of the Company's successful drilling program at Niton, the Compton owned McLeod River gas plant will be operating at maximum capacity of 20 MMcf/d in the first half of 2006. The Company is currently evaluating plant expansion alternatives, as well as the option of routing a portion of its production to adjacent non-operated plants, in which the Company holds minor working interests.

PEACE RIVER ARCH

The Peace River Arch area, located north of Grande Prairie, contains multi-zone exploration and development opportunities. This area includes both light oil production at Cecil/Worsley and natural gas exploration at Howard and Pouce Coupe. The Company averages a 61% working interest in 199,040 (121,634 net) acres of land in the area. In 2005, Compton drilled 124 (114 net) wells in the Arch with an 89% success rate and plans to drill 106 wells in 2006.

Cecil/Worsley



Compton's 2005 drilling program at Worsley was extremely successful, significantly increasing the reserve value and production from the area. The Company drilled 80 Charlie Lake oil wells, more than twice the original number budgeted, which resulted in pool boundary extensions in all directions.

Approval for a pool wide waterflood on the Charlie Lake H and J pool at Worsley was received in February 2005 and a total of eight wells have been converted to injectors thus far. The waterflood is projected to increase the ultimate recovery factor for the pool to 25% from 15% on primary depletion. The Company will continue its program at Worsley in 2006 and anticipates drilling 90 wells in the upcoming year.

At Cecil, 23 100% working interest and 9 non-operated 40% working interest horizontal Charlie Lake oil wells were drilled in 2005. All wells encountered excellent pay zones and have been systematically brought on production throughout 2005 and into the first quarter of 2006. Compton is undertaking geological and engineering work to evaluate additional waterflood potential in the Cecil area. The Company plans to drill 17 wells in 2006 and to focus on optimizing production from its previously drilled horizontal wells.

Operating Results

UNDEVELOPED LAND

In 2005, Compton continued to expand its land base to maintain a dominant land position in its core areas. The Company's total net land inventory increased 6% in 2005, with acquisitions occurring primarily in the Company's Southern and Central Alberta core areas, while net undeveloped land increased 1% from the prior year. The Company has an average 76% working interest in its undeveloped land base, reflecting Compton's strategy to establish high ownership levels and control of operations.

Total Land
(net acres 000s)

During 2006, Compton plans to continue to invest in the future and expand in its core areas. The Company's 2006 budget includes $71 million directed towards land acquisitions and seismic surveys in its major operating areas.

	Undeveloped Acres		Total Acres	
Area	Gross	Net	Gross	Net
Southern Alberta	464,730	409,678	804,007	699,751
Central Alberta	273,614	186,069	541,643	297,475
Peace River Arch	108,560	75,772	199,040	121,634
Northern Alberta	60,578	32,629	76,418	39,758
Other	63,835	34,806	88,874	37,174
December 31, 2005 total	**971,317**	**738,954**	**1,709,982**	**1,195,792**
December 31, 2004 total	1,019,854	729,429	1,670,048	1,122,860

DRILLING ACTIVITY

Compton drilled 392 gross (334 net) wells in 2005 with a 96% success rate, compared with 186 gross (146 net) wells drilled in 2004.

Wells Drilled
(# of gross wells)

Of the 392 wells drilled in 2005, 80% were classified as development wells and 20% were classified as exploratory wells, compared to 77% and 23% respectively in 2004. The higher percentage of development wells in the current year reflects the increasing maturity of our oil and gas plays.

Years ended December 31,	Natural Gas	Oil	D&A	Total	Net	Success
Southern Alberta	190	1	2	193	181	99%
Central Alberta	62	8	2	72	37	97%
Peace River Arch	5	105	13	123	114	89%
	257	114	17	388	332	96%
Standing, cased wells				4	2	
2005 Total				**392**	**334**	
2004 Total	136	28	18	186	146	90%

RESERVES

For the year ended December 31, 2005, Netherland, Sewell Associates, Inc. ("Netherland Sewell") independently evaluated 100% of Compton's reserves.

As required by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), Compton filed Form 51-101 F1 as part of its Annual Information Form ("AIF"). The AIF is very comprehensive, therefore certain information has been summarized with respect to operations and presented in the following sections. All such information is consistent with the Form NI 51-101 F1 filing and the Company's extended disclosure contained in the AIF is available on both the SEDAR website and Compton's website.

Summary of Estimated Reserve Volumes - Forecast Prices and Costs (1)

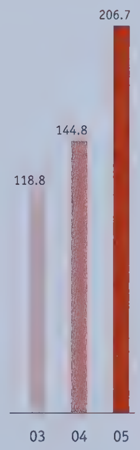
	Crude Oil		Natural Gas		NGL's		Sulphur		Total	
As at December 31, 2005	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mlt)	Net (Mlt)	Gross (Mboe)	Net (Mboe)
Proved										
Developed producing	13,537	12,533	424	344	7,837	5,591	1,603	1,426	93,637	76,937
Developed non-producing	3,131	2,888	44	35	828	568	52	41	11,400	9,394
Undeveloped	5,019	4,304	84	70	1,731	1,283	118	98	20,923	17,366
Total proved	21,688	19,725	553	450	10,396	7,441	1,773	1,565	125,960	103,697
Probable	6,805	5,762	401	338	6,232	4,629	772	656	80,712	67,334
Total proved plus probable	**28,493**	**25,488**	**954**	**788**	**16,628**	**12,070**	**2,545**	**2,221**	**206,672**	**171,031**
2004 total proved plus probable	20,267	17,687	650	528	13,577	9,776	2,540	2,236	144,777	117,672

(1) Numbers may not add due to rounding.

In 2005, Compton added 62 MMboe to its proved and probable reserves through drilling successes, acquisitions, and extensions. Total proved plus probable reserves increased 43% from the prior year to 207 MMboe.

Compton's total proved reserve base is comprised 73% by natural gas and 27% by liquids. Proved producing reserves comprise 74% of total proved reserves, while total proved reserves account for 61% of the proved plus probable reserves. The Company has a 12 year reserve life index on a proved basis.

Proved + Probable Reserves
(MMboe)



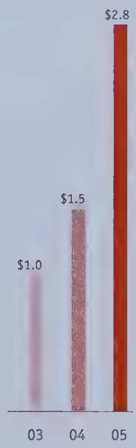
Net Present Value of Reserves - Forecast Prices and Costs (1)

	Future net revenue before income taxe discounted at a rate of		
($000,000s)	0%	8%	10%
Proved			
Producing	$ 2,809	$ 1,502	$ 1,367
Non-producing	407	231	209
Undeveloped	674	278	235
Total proved	3,890	2,012	1,811
Probable	2,308	830	681
Total proved plus probable	**$ 6,199**	**$ 2,842**	**$ 2,493**
2004 proved plus probable	$ 3,100	$ 1,477	$ 1,304

(1) Pricing assumptions are the average of four major Canadian oil and gas evaluation firms. Numbers may not add due to rounding.

Future net revenues are calculated based upon estimated revenue less royalties, operating costs, future development costs, and well abandonment costs. Estimated income taxes have not been deducted. The net present value should not be considered the current market value of the Company's reserves or the costs that would be incurred to obtain equivalent reserves.

Net Present Value of Reserves P+P @ 8%
($billion)



Reserve Reconciliation (net after royalties) - Forecast Prices and Costs

	Crude Oil, NGLs, and Sulphur			Natural Gas		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
December 31, 2004	18,719	10,980	29,699	359,029	168,808	527,837
Extensions	1,972	2,633	4,605	33,694	118,596	152,290
Improved recovery	3,816	2,050	5,866	10,555	83,259	93,814
Technical revisions	4,862	(4,882)	(20)	61,544	(45,976)	15,568
Discoveries	669	87	756	16,310	12,362	28,672
Acquisitions	722	179	901	5,564	670	6,234
Dispositions	(2)	–	(2)	(56)	–	(56)
Production	(2,027)	–	(2,027)	(36,850)	–	(36,850)
December 31, 2005	**28,731**	**11,047**	**39,778**	**449,790**	**337,719**	**787,509**

FD&A Costs
($/boe)

FINDING & DEVELOPMENT COSTS

Finding, development and acquisition ("FD&A") costs associated with the 2005 exploration and development program, including revisions and changes in future capital, were $15.42/boe on a proved basis and $13.02/boe on a proved plus probable basis. Excluding acquisitions, finding and development ("F&D") costs were $15.48/boe proved and $13.05/boe proved plus probable.

It should be noted that the aggregate of the exploration and development costs incurred in 2005 and the change during the year in estimated future development costs, generally will not reflect total F&D costs related to reserves additions for the year.

FD&A Costs

($/boe)	**2005**	2004	2003	3 Year Average
Including future capital				
Proved	**$ 15.42**	$ 14.91	$ 20.91	$ 16.26
Proved plus probable	**$ 13.02**	$ 13.19	$ 14.11	$ 13.35
Excluding future capital				
Proved	**$ 12.84**	$ 13.87	$ 18.71	$ 14.09
Proved plus probable	**$ 7.05**	$ 8.51	$ 8.95	$ 7.80

Compton recognizes the importance and positive impact that results from responsible corporate citizenship. The Company is committed to behaving ethically and contributing to economic development while improving the quality of life of employees, their families, and the local community. Compton believes in giving back to the communities in which it operates and supported numerous local initiatives throughout 2005.

Corporate Citizenship

Compton recognizes the importance and positive impact that results from responsible corporate citizenship. The Company is committed to behaving ethically and contributing to economic development while improving the quality of life of employees, their families, and the local community. Compton believes in giving back to the communities in which it operates and supported numerous local initiatives throughout 2005.

EDUCATIONAL PARTNERSHIPS

For the past five years, Compton has formed a Corporate/Educational Partnership with a Calgary Board of Education Public School. During the 2004-2005 school year, Compton partnered with Harold W. Riley Elementary School to support a variety of school initiatives as identified by the school's staff, parents and students. As a result of the partnership, Jim Sproule, Principal of Harold W. Riley said, "Your financial support has made a tremendous and uplifting contribution to our students and parents...it is difficult to describe how appreciative teachers and students are for the funds that enhance our school curriculum, special programs and events."

Compton has formed two Educational Partnerships for the 2005-2006 school year. Our educational partnerships will once again focus on enabling and assisting the staff at each school as they work to enhance the quality of educational opportunities and experiences for the students at Falconridge Elementary School in Calgary and Spitzee Elementary School in High River.

COMMUNITY PARTICIPATION

Compton's Corporate Sponsorship and Donation Programs contribute to numerous charities and community endeavors that enhance the quality of life in the areas where the Company is active.

Environment, Health and Safety

The Human Resources, Compensation, Environmental, Health and Safety Committee of the Board of Directors undertakes, with management, all necessary procedures, policies, and industry best practices designed to protect Compton's employees, contractors, members of the public, and the environment. The Company regularly assesses its operations, at both the corporate and field levels, in an effort to identify opportunities to improve environmental, health, and safety performance. By meeting or surpassing all applicable regulatory requirements, education and training of personnel on EHS policies and procedures and following industry best practices, Compton believes its operations are safer for its employees, neighbours, and stakeholders.

ENVIRONMENT

Compton believes that protection of the environment is key to both the success and reputation of the Company. Structuring Compton's operations to minimize the impact to the environment is an important value that the Company demonstrates on a continuous basis. Compton's commitment to the environment is exemplified by:

- site inspections and assessments to ensure compliance with environmental laws and regulations;
- participation in industry programs that benchmark and measure the Company's performance against industry peers;
- continuous improvement in comparison to the industry averages;
- sharing best practices through networking with peer associations;
- considering and implementing environmental requirements applicable to the Company's operations;
- reduction of emissions, efficient use of energy, and an ongoing effort to conserve natural resources; and
- an ongoing effort to minimize Compton's ecological footprint in the areas in which the Company is present.

HEALTH AND SAFETY

Health and safety is fundamental to Compton's values and the Company is committed to carrying out its operations in a safe and responsible manner. Compton requires that all employees, contractors, and subcontractors are familiar with and adhere to the Company's safety policies and procedures, regulatory legislation, industry guidelines, and best practices. Compton has not experienced an employee lost time accident since January 2001 and continues to lower its employee total recordable injuries, contractor lost time ratio, and contractor total recordable injury ratio.

Compton is committed to continuous improvement of its health and safety practices, and undertakes initiatives such as:

- hazard assessments of the Company's work sites and operations;
- setting goals and targets in industry recognized categories, such as lost time accidents, days away from work, and total recordable injuries;
- tracking, investigating, and following-up all incidents and near misses;
- developing effective, emergency response plans as well as conducting routine training and scenarios to test and improve the emergency response plans;
- openly reporting the Company's health and safety practices to allow comparison with industry averages and top safety performers;
- working to improve contractor safety; and
- maintaining an industry recognized safety program.

M.F. Belich

I.J. Koop

J.W. Preston

J.T. Smith

J.A. Thomson

E.G. Sapieha

Compton's Board of Directors believes that adopting and maintaining the highest standards of corporate governance is a critical aspect of the overall success of the Company [illegible] builds shareholder confidence. Sound corporate governance ensures transparency and accountability for Compton's objectives, strategies, controls and overall performance. The Corporate Governance Committee and Board of Directors continuously monitor applicable legislation and respond appropriately to ensure the Company's compliance.

Corporate Governance

Compton's Board of Directors believes that adopting and upholding the highest standards of corporate governance is critical in respect of the overall success of the Company and to build stakeholder confidence. Sound corporate governance ensures transparency and accountability for Compton's objectives, strategies, controls, and overall performance. The Corporate Governance Committee and Board of Directors continuously monitor applicable legislation and respond appropriately to ensure the Company's compliance.

Compton continually adjusts its practices to reflect the requirements of the New York Stock Exchange ("NYSE") Listing Standards and the Sarbanes-Oxley Act of 2002. In addition, the Company has established procedures for the confidential, anonymous submission by staff of concerns regarding any questionable accounting or auditing matters. Compton also has a Code of Business Conduct and Ethics applicable to all Directors, Officers, and employees and a Code of Ethics for its senior financial officers.

CANADIAN CORPORATE GOVERNANCE REQUIREMENTS

The Canadian Securities Administrators approved National Policy 58-201, "Corporate Governance Guidelines" (the "Best Practices Policy") and National Instrument 58-101, "Disclosure of Corporate Governance Practices" (the "Disclosure Instrument"), effective June 30, 2005. The Best Practices Policy provides guidance on corporate governance practices, following U.S. initiatives under the Sarbanes Oxley Act and newly adopted corporate governance rules of the NYSE and NASDAQ. The Disclosure Instrument specifically requires issuers to make certain corporate governance related disclosures. The disclosures required under the Disclosure Instrument generally correspond to the guidance in the Best Practices Policy.

A description of the Company's corporate governance disclosures, as required by the Disclosure Instrument, is set forth in the Company's Management Information Circular, which may be found on the Company's website.

U.S. CORPORATE GOVERNANCE REQUIREMENTS

Compton's common shares commenced trading on the NYSE on December 6, 2005. The Company is classified as a foreign private issuer in the United States by the Securities Exchange Act of 1934 (the "Exchange Act") and is therefore permitted to follow Canadian corporate governance regulations, except for:

- audit committee member independence requirements under Rule 10A-3 of the Exchange Act;
- the requirement to disclose any significant differences between the Company's corporate governance practices and those followed by domestic companies under the NYSE listing standards; and
- the requirement for the Company to submit an Annual Written Affirmation to the NYSE, confirming the Company's compliance with the audit committee independence requirements of Rule 10A-3 and that the Company has provided a statement of significant corporate governance differences, and to notify in writing the NYSE if any Officer becomes aware of a material non-compliance.

Compton's audit committee members are independent under Rule 10A-3 of the Exchange Act. The Company's corporate governance practices do not differ significantly from those followed by domestic U.S. companies under NYSE listing standards, with the exceptions that (i) Compton does not have an internal audit function and (ii) the CEO's compensation is finally approved by the Board of Directors on the recommendation of the Human Resources, Compensation, Environmental, Health and Safety Committee. Compton has filed its Annual Written Affirmation with the NYSE.

BOARD OF DIRECTORS AND BOARD COMMITTEES

Board Mandate and Composition

The Board of Directors (the "Board") has explicitly assumed responsibility for the stewardship of the Company. The Board operates by delegating certain of its authorities to Management, including the day to day conduct of the business of the Company, while reserving certain powers for itself. The Board's fundamental objectives are to enhance and preserve long term shareholder value, to provide stewardship in order that the Company meets its obligations on an ongoing basis, and to operate in a reliable and safe manner.

The written Charter of the Board explicitly acknowledges responsibility for the stewardship of the Company and requires the Board to determine that:

- the Company has established long term goals and a strategic planning process;
- the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks;
- there is sufficient succession planning including appointing, training, managing, and monitoring Management;
- the Company has a communications policy;
- the Company's internal controls and management information systems have sufficient integrity; and
- the Company's approach to governance issues and the implementation of principles for the management of corporate governance fosters a culture of integrity throughout the Company.

Based upon applicable Canadian and U.S. securities laws and the NYSE corporate governance rules, Compton has adopted "Standards of Independence," which may be viewed in full on the Company's website. The Board must affirmatively determine on an annual basis, whether or not its members are independent. Five out of six Directors, including the Chairman of the Board, have been determined to be independent. Mr. Sapieha is a non-independent Director because of his position as President & CEO of the Company.

A full copy of the Charter for the Board of Directors can be found on the Company's website at www.comptonpetroleum.com.

Committees of the Board

Subject to applicable law, the Board may delegate its powers, duties, and responsibilities to Committees of the Board. In this regard, the Board has established four standing Committees, the (i) Human Resources, Compensation, Environmental, Health and Safety Committee; (ii) Audit, Finance and Risk Committee; (iii) Engineering, Reserves and Operations Committee; and (iv) Corporate Governance Committee. The mandate of each committee is reviewed annually and is summarized below. All Committees are composed exclusively of independent Directors.

HUMAN RESOURCES, COMPENSATION, ENVIRONMENTAL, HEALTH AND SAFETY COMMITTEE

CHAIRMAN: Irvine Koop

MEMBERS: Mel Belich, John Preston, Jeff Smith, John Thomson

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to human resources and compensation. Additionally the Committee monitors the environmental, health, and safety practices and procedures of the Company for compliance with applicable legislation, conformity with industry standards, and prevention or mitigation of loss.

The Committee also has the responsibility to:

- review and oversee human resources policies of the Company;
- review succession plans for key Management positions within the Company;
- develop performance objectives for the CEO and other Officers and assess their performance against such objectives;
- recommend to the Board, salary and other remuneration for Officers of the Company;
- monitors performance objectives for Officers in order that they are aligned with shareholders' interests and corporate goals;
- recommend to the Board in respect of all other compensation matters, including long and short term incentives such as bonuses, stock option plans, and other benefits; and
- review and recommend compensation for Board and Committee service.

The Committee fulfils its environmental, health, and safety responsibilities by:

- overseeing the Company's policies and guidelines with respect to environmental, health, and safety matters regarding the Company's facilities and operations;
- undertaking with management those policies, guidelines, practices, and procedures designed to manage risk and assume compliance with all workplace, environmental, health, and safety laws;
- reviewing and monitoring the Company's policies, procedures, and practices relating to the documentation and reporting of environmental, health, and safety regulatory approvals, compliance, and incidents; and
- generally, reviewing the Company's performance related to environment, health, and safety and confirming with management that long range preventative programs are in place.

The full Human Resources, Compensation, Environmental, Health and Safety Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

AUDIT, FINANCE AND RISK COMMITTEE

CHAIRMAN: John Thomson

MEMBERS: Mel Belich, Irvine Koop, John Preston, Jeff Smith

The Audit, Finance and Risk Committee is mandated to oversee that Management is responsible for creating and maintaining an effective risk management and internal control framework. This framework provides reasonable assurance that the financial, operational, and regulatory objectives of the Company are achieved and that the statutory responsibilities of Board are discharged.

The Committee fulfills its role on behalf of the Board by overseeing:

- the review, disclosure, and integrity of the Company's financial statements, Management's Discussion and Analysis of financial conditions and results of operations and other financial information;
- the external auditor's qualifications, independence, and performance;
- the Company's compliance with legal and regulatory requirements;
- risk management, management information systems, governmental legislation, and external business of the Company;
- the effectiveness and integrity of the Company's system of disclosure controls and internal controls; and
- the appointments of the Chief Financial Officer and other key financial executives.

The Committee oversees the operation of an anonymous and confidential toll free telephone number for employees, contractors, and others to call with respect to accounting irregularities or ethical violations. The Committee has also established a procedure for the receipt, retention, treatment, and regular review of any such reported activities. This telephone number — 1-888-929-9093 is published on the Compton's website at www.comptonpetroleum.com.

The full Audit, Finance and Risk Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

ENGINEERING, RESERVES AND OPERATIONS COMMITTEE

CHAIRMAN: Jeff Smith

MEMBERS: Mel Belich, Irv Koop, John Preston, John Thomson

The Committee's mandate is to review and make recommendations to the Board on the Company's engineering and reserves policies.

The Committee fulfills its oversight role on behalf of the Board and is responsible for:

- the Company's overall policies and guidelines with respect to engineering, reserves, and operations;
- undertaking with Management all necessary procedures and policies to comply with regulations and guidelines applicable to the Company and enunciated by the applicable regulatory authorities including providing assistance to Management in compliance with National Instrument 51-101, preparation of the Statement of Reserves (Form 51-101 F1), Evaluator's Report (Form 51-101 F2), and Management Report (Form NI 51-101 F3);
- meeting with the Company's Vice President of Operations & Engineering, other senior reserves personnel, and the independent reserves evaluator to review and consider the Company's reserves; and
- reviewing, assisting, and making recommendations to the Board in respect of the annual appointment of the Company's independent qualified reserves evaluators.

The full Engineering, Reserves and Operations Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

CORPORATE GOVERNANCE COMMITTEE

CHAIRMAN: Mel Belich

MEMBERS: Irv Koop, John Preston, Jeff Smith, John Thomson

The Corporate Governance Committee is responsible for developing the Company's approach to governance issues and to assist the Board in fulfilling its oversight responsibilities with respect to the development and implementation of corporate governance. The Committee functions with a view to fostering a culture of integrity within the Company.

The Committee fulfills its oversight role on behalf of the Board and is responsible to:

- recommend initiatives to maintain high standards of corporate governance;
- assess the effectiveness and performance of the Board as a whole, the Chairman of the Board, Board Committees, Committee Chairs, and individual Directors;
- define and monitor the relationship, roles, and authority of the Board and Management;
- review and evaluate corporate communication policies and practices; and
- monitor compliance with the Code of Business Conduct and Ethics.

The Committee also has the responsibility to:

- identify nominees for the Board and its Committees;
- evaluate the competencies and skills necessary for the Board as a whole to possess, the competencies and skills that existing Directors possess, and the competencies and skills each new nominee will bring to the Board;
- propose nominees for re-election as Directors by the shareholders at the annual meeting; and
- propose candidates for appointment to senior Management, executive, and Officer positions.

The full Corporate Governance Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

CODE OF BUSINESS CONDUCT AND ETHICS

Compton's Code of Business Conduct and Ethics (the "Code") holds the Company's Directors, Officers, employees, and consultants to high standards of legal and moral conduct in all areas of operations. In addition to meeting legal and regulatory requirements, the Company strives to conduct all operations fairly and with integrity.

The Board encourages and promotes a culture of ethical business conduct through its guidance provided to Officers and senior members of Management and its oversight of the daily operations of the Company. Additionally, the Whistle Blower Policy (the "Policy") adopted by the Company promotes a culture of openness, honestly, and accountability. The Policy establishes procedures for the receipt, retention, treatment, and regular review of any unlawful activities, accounting irregularities or ethical violations.

The Board monitors compliance with the Code through the use of an Ethics Hotline, which is an anonymous and confidential toll free telephone number. Additionally, any violations of the Code brought to the attention of Management are reported to the Board. No waivers from the Code were granted to the Company's Directors, Officer, employees, or consultants in 2005.

Compton's Code of Business Conduct and Ethics and Whistle Blower Policy may be viewed on the Company's website at www.comptonpetroleum.com.

Management's Discussion and Analysis Advisories

Management's Discussion and Analysis ("MD&A") is intended to provide both an historical and prospective view of the Company's activities. The MD&A was prepared as at March 15, 2006 and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2005. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to U.S. GAAP is included in Note 19 to the consolidated financial statements.

Additional advisories with respect to forward looking statements, the use of Non-GAAP Financial Measures, and the use of BOE volumetric measures are set out at the end of this MD&A.

CONTENTS

Management's Discussion and Analysis

CORPORATE OVERVIEW & STRATEGY

Compton Petroleum Corporation is an independent, public company actively engaged in the exploration, development, and production of natural gas, natural gas liquids, and crude oil in Western Canada. The Company's activities are concentrated in three core geographic areas, primarily in Alberta, in the Western Canada Sedimentary Basin. Compton's growth and reserve base has resulted predominantly from exploration and development activities, complemented by strategic acquisitions.

Compton's objective has been and remains that of building an exploration and development company capable of delivering and sustaining long term growth. Management has adhered to a consistent strategy in pursuing this objective. Major components of Management's strategy currently include:

- concentrating activities in a limited number of core areas;
- focusing on unconventional natural gas in large resource plays;
- pursuing growth through the drill bit, complemented by selective acquisitions;
- controlling infrastructure and operatorship; and
- maintaining financial flexibility.

Cash Flow from Operations
($mm)

RESULTS OF OPERATIONS

Executive Summary

- Drilling program included 392 wells in 2005, with a 96% success rate, more than double the 186 wells drilled in 2004.
- Annual production averaged 29,424 boe/d, a 9% increase from the prior year.
- Cash flow from operations increased 57% to $278 million driven by production growth and strong commodity prices.
- Operating earnings for the year rose 100% to $94 million.
- Net earnings for the year increased 28% to $81 million.

Net Earnings
($mm)

Cash Flow from Operations and Net Earnings

Years ended December 31,		**2005**	2004	2003
Cash flow from operations (1) ($000s)		**$ 278,112**	$ 177,131	$ 154,893
Per share:	basic	**$ 2.21**	$ 1.51	$ 1.33
	diluted	**$ 2.11**	$ 1.43	$ 1.27
Net earnings ($000s)		**$ 81,326**	$ 63,633	$ 118,880
Per share:	basic	**$ 0.65**	$ 0.54	$ 1.02
	diluted	**$ 0.62**	$ 0.51	$ 0.97

(1) Cash flow from operations represents net earnings before depletion and depreciation, future income taxes, and other non-cash expenses.

Cash flow from operations in 2005 reached a new high as a result of strong commodity prices and increasing production levels.

Net earning in 2005 increased $18 million, or 28%, from 2004 and were reduced by non-recurring one-time costs of $14.4 million ($20.8 million before taxes) relating to the repurchase of U.S.$158.25 million of 9.90% Senior Notes. See discussion on Tender Costs.

The following table reconciles cash flow from operating activities to cash flow from operations.

Years ended December 31, ($000s)	2005	2004	2003
Cash flow from operating activities, as reported	$ 286,553	$ 164,537	$ 156,211
Changes in non-cash operating working capital items	(8,441)	12,594	(1,318)
Cash flow from operations	$ 278,112	$ 177,131	$ 154,893

Operating Earnings

Operating Earnings
($000)

Operating earnings is a non-GAAP measure that adjusts net earnings by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of operating earnings has been prepared to provide investors with information that is more comparable between years.

SUMMARY OF OPERATING EARNINGS

Years ended December 31, ($000s except per share amounts)	2005	2004	2003
Net earnings, as reported	$ 81,326	$ 63,633	$ 118,880
Non-operational items, after tax			
Unrealized foreign exchange (gain)	(6,339)	(11,821)	(37,761)
Unrealized risk management loss	6,345	1,338	–
Stock-based compensation	3,682	2,094	451
Tender costs on repurchase of 9.90% notes	14,414	–	–
Future tax recovery due to tax rate reductions	(5,764)	(8,359)	(37,130)
Operating earnings	$ 93,664	$ 46,885	$ 44,440
Per share: basic	$ 0.75	$ 0.40	$ 0.38
diluted	$ 0.71	$ 0.38	$ 0.36

The same factors that drove the increase in cash flow from operations - strong commodity prices and higher production volumes - resulted in 2005 operating earnings almost doubling the prior year level.

Revenue

Revenue
($mm)

Years ended December 31,	2005	2004	2003
Average production			
Natural gas (MMcf/d)	131	123	118
Liquids (bbls/d)	7,646	6,330	5,924
Total (boe/d)	29,424	26,876	25,552
Benchmark prices			
NYMEX (U.S.$/mmbtu)	$ 8.55	$ 6.09	$ 5.60
AECO ($/Mcf)	$ 8.04	$ 6.44	$ 6.35
WTI (U.S.$/bbl)	$ 56.56	$ 41.40	$ 31.04
Edmonton par ($/bbl)	$ 68.72	$ 52.37	$ 43.14
Realized prices			
Natural gas ($/Mcf)	$ 8.42	$ 6.46	$ 6.27
Liquids ($/bbl)	$ 56.04	$ 43.21	$ 35.59
Total ($/boe)	$ 51.95	$ 39.82	$ 37.16
Revenue ($000s)			
Natural gas	$ 401,468	$ 291,565	$ 269,622
Liquids	156,411	100,094	76,943
Total	$ 557,879	$ 391,659	$ 346,565

Revenue in 2005 increased from the comparable period due to a combination of increased production volumes and higher realized prices.

SUMMARY OF REVENUE INCREASES FROM PRODUCTION AND PRICING

($000s)	Natural Gas Revenue	Liquids Revenue	Total Revenue
Reported 2004 revenue	$ 291,565	$ 100,094	$ 391,659
Increase in production volumes	21,659	26,579	48,238
Increase in prices	88,244	29,738	117,982
Reported 2005 revenue	$ 401,468	$ 156,411	$ 557,879

Production volumes in 2005 increased 9% from 2004 as a result of the Company's 2005 drilling program. Production growth in Southern Alberta, which accounts for 60% of Compton's total volumes, was hampered by abnormally wet weather conditions during the summer months. Well completions, pipeline constructions, and tie-ins scheduled for the second and third quarters were delayed by field conditions, partially offsetting Compton's aggressive efforts to increase annual production volumes.

Compton's natural gas production is sold under a combination of longer term contracts with aggregators and short term daily or 30 day AECO indexed contracts. Approximately 10% of the Company's natural gas production in 2005 was committed to aggregators, compared to an average of 11% in 2004. The average aggregator price realized in 2005 was $1.25/Mcf less than the non-aggregator prices realized during the year.

Compton's crude oil sales are priced based upon Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to obtain the most favourable pricing. The Company sells crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

From time to time, Compton may enter into hedging arrangements to mitigate commodity price risk. In accordance with the Company's policy, hedging programs will not exceed 50% of non-contracted production. Commodity hedge gains and losses are reflected in "Risk Management" on the consolidated income statements.

Royalties

Years ended December 31, ($000s except where noted)	**2005**	2004	2003
Crown royalties	**$ 106,253**	$ 75,859	$ 68,360
Other royalties	**26,890**	17,939	14,706
Total royalties	**133,143**	93,798	83,066
Alberta royalty tax credit	**(426)**	(382)	(500)
Net royalties	**$ 132,717**	$ 93,416	$ 82,566
Percentage of revenues	**23.8%**	23.9%	23.8%

The Alberta royalty structure is based upon commodity prices and well productivity, with higher prices and well productivity attracting higher royalty rates. In 2005, the increase in the rate associated with increased prices is offset by increased oil production and an increase in the number of lower productivity gas wells, both which attract lower royalty rates.

Operating Expenses

Years ended December 31,	**2005**	2004	2003
Operating expenses ($000s)	**$ 66,802**	$ 55,655	$ 49,916
Operating expenses per boe ($/boe)	**$ 6.22**	$ 5.66	$ 5.35

Operating costs per boe increased year over year due to an overall rise in industry costs and the additional lifting costs associated with increased oil production. High commodity prices in 2005 accelerated activity throughout the oil and gas industry, increasing the demand for and cost of goods and services. Particular increases of note include salaries for additional field staff and contract operators, rising electricity prices in the latter half of 2005, salt water disposal, and emulsion processing.

Transportation

Years ended December 31,	**2005**	2004	2003
Transportation costs ($000s)	**$ 10,858**	$ 8,595	$ 8,447
Transportation costs per boe ($/boe)	**$ 1.01**	$ 0.87	$ 0.91

Compton incurs charges on the transportation of its production from the wellhead to the point of sale. Pipeline tariffs and trucking rates for liquids are primarily dependent upon production location and distance from the sales point. Regulated pipelines transport natural gas within Alberta at tolls approved by the government.

Higher transportation costs in 2005 result from a combination of trucking costs associated with increased crude oil production and surcharges associated with rising fuel costs.

General and Adminstrative Expenses

Years ended December 31, ($000s except where noted)	**2005**	2004	2003
General and administrative expenses	**$ 31,451**	$ 24,663	$ 20,355
Capitalized general and administrative expenses	**(3,647)**	(2,683)	(3,321)
Operator recoveries	**(6,581)**	(6,765)	(4,828)
Total general and administrative expenses	**$ 21,223**	$ 15,215	$ 12,206
General and administrative per boe ($/boe)	**$ 1.98**	$ 1.55	$ 1.31

As budgeted, general and administrative costs increased 39% in the last year. The major component in this year over year increase, contributing 32%, was additional employee costs associated with increased personnel levels and a general increase in salaries necessary to attract and retain qualified personnel in a very competitive industry. Other increases result from the current regulatory environment including Sarbanes Oxley compliance and the resulting increase in legal, audit, and reserve evaluation costs.

Interest Expense

Years ended December 31, ($000s)	**2005**	2004	2003
Interest on bank debt, net	**$ 11,520**	$ 9,662	$ 6,611
Interest on Senior Notes	**20,912**	21,281	21,711
Interest expense	**32,432**	30,943	28,322
Finance charges	**2,519**	2,790	2,273
Total interest and finance charges	**$ 34,951**	$ 33,733	$ 30,595

Interest costs in 2005 increased from the prior period due to higher debt levels, precipitated by capital expenditures exceeding cash flow throughout 2005. Interest costs have also been affected by rising interest rates. The impact on interest expense of issuing U.S.$300 million of 7⅝% Senior Notes late in the year was minimal.

Tender Costs

Years ended December 31, ($000s)	**2005**
Premium payment	**$ 7,814**
Consent solicitation fee	**5,883**
Pro-forma reduction of deferred financing charges on repayment of 9.90% Senior Notes	**7,053**
Total tender costs	**$ 20,750**

In November 2005, the Company and a wholly owned subsidiary of the Company completed a tender offer and consent solicitation to purchase Compton's 9.90% Senior Notes due in 2009. Holders of U.S.$158.25 million (approximately 96%) of the outstanding 9.90% Notes tendered the notes and delivered consents to amend the Indenture. The premium payment for notes tendered was 104.195% plus accrued and unpaid interest, and the note holders that delivered consents received 103% for a total consideration of 107.195%.

The unamortized portion of deferred financing charges related to the tendered portion of the 9.90% Senior Notes of $7.1 million was also included in tender costs.

Netbacks

Years ended December 31, ($/boe)	**2005**	2004	2003
Realized price	**$ 51.95**	$ 39.82	$ 37.16
Royalties, net	**(12.36)**	(9.50)	(8.85)
Operating expenses	**(6.22)**	(5.66)	(5.35)
Transportation	**(1.01)**	(0.87)	(0.91)
Field operating netback	**$ 32.36**	$ 23.79	$ 22.05
General and administrative	**(1.98)**	(1.55)	(1.31)
Interest	**(3.25)**	(3.43)	(3.28)
Current taxes	**(0.47)**	(0.28)	(0.35)
Cash flow netback	**$ 26.66**	$ 18.53	$ 17.11

Field Netbacks
($/boe)(6:1)

Risk Management

Compton's financial results are impacted by external market risks associated with fluctuations in commodity prices, interest rates, and the Canadian/U.S. exchange rate. The Company utilizes various financial instruments for non-trading purposes to manage and mitigate its exposure to these risks. The Company records financial instruments, not designated or not qualifying for hedge accounting, at fair value on the consolidated balance sheets, with subsequent changes recognized in consolidated net earnings.

Financial instruments utilized to manage risk are subject to periodic settlements throughout the term of the instruments. Such settlements may result in a gain or loss to the Company which is recognized as a realized Risk Management gain or loss at the time of settlement.

The mark-to-market fair value of a financial instrument outstanding at the end of a reporting period, reflects the value of the instrument based upon the market conditions existing as of that date. Any change in the fair value of the instrument from that determined at the end of the previous reporting period is recognized as an unrealized Risk Management gain or loss. Unrealized Risk Management gains or losses so recognized may or may not be realized in subsequent periods depending upon subsequent moves in commodity prices, interest rates, or exchange rates affecting the financial instrument.

The mark-to-market fair value method of accounting for financial instruments and the recognition of unrealized gains and losses in determining earnings has introduced an additional element of volatility in earnings that may not be particularly meaningful in assessing the Company's financial performance between periods.

Risk management gains and losses recognized in 2005 are outlined below.

Years ended December 31, ($000s)	**2005**	2004	2003
Commodity contracts			
Realized loss	**$ 9,663**	$ 9,151	$ 5,497
Unrealized loss (gain)	**5,136**	(1,985)	–
Cross currency interest rate swap			
Realized (gain)	**(532)**	(2,522)	(1,365)
Unrealized loss	**5,035**	4,164	–
Total risk management loss	**$ 19,302**	$ 8,808	$ 4,132
Realized loss	**$ 9,131**	$ 6,629	$ 4,132
Unrealized loss	**10,171**	2,179	–
Total risk management loss	**$ 19,302**	$ 8,808	$ 4,132

Depletion and Depreciation

Years ended December 31,	**2005**	2004	2003
Total depletion and depreciation ($000s)	**$ 105,504**	$ 82,554	$ 61,749
Depletion and depreciation per boe ($/boe)	**$ 9.82**	$ 8.39	$ 6.62

The Company's 2005 provision for depletion and depreciation increased $23 million or 28% over 2004. Approximately one third of this increase was due to the increase in 2005 production over that of 2004 with the balance being the result of an overall increase in the depletion and depreciation rate as determined on a boe basis. The depletion and depreciation rate on a boe basis reflects increased costs relating to exploration and development activities as discussed in capital expenditures.

Foreign Exchange

The foreign exchange gain recognized on the consolidated statements of earnings results primarily from the translation of the Company's U.S. dollar denominated Senior Notes into Canadian dollars. The Senior Notes are translated and recorded in the financial statements at the year end exchange rate, with any differences from prior measurements recorded as unrealized foreign exchange gain or loss.

The Canadian/U.S. exchange rate increased to one Canadian Dollar being equal to U.S.$0.8577 on December 31, 2005 from one Canadian Dollar being equal to U.S.$0.8308 at December 31, 2004, resulting in the Company recording a $7 million foreign exchange gain in 2005.

On November 22, 2005, pursuant to a tender offer, the Company repurchased U.S.$158.25 million of the 9.90% Senior Notes issued in 2002. As a result of the repurchase, the Company crystallized $62.2 million of the accumulated unrealized foreign exchange gains that had been previously recognized with the strengthening of the Canadian dollar subsequent to the note issuance.

Stock-based Compensation

Years ended December 31,	**2005**	2004	2003
Options granted (000s)	**2,930**	2,549	1,503
Weighted average fair value of options granted ($/share)	**$ 5.45**	$ 3.70	$ 3.01
Stock-based compensation expense recognized ($000s)	**$ 5,903**	$ 3,410	$ 760

Compton has a stock option plan for Directors, Officers, and employees. The plan is designed to attract, motivate, and retain outstanding individuals and to align their success with that of the Shareholders through achieving corporate objectives. The fair value of options granted is estimated on the date of grant using the Black-Scholes option pricing model and the associated compensation expense is recognized over the vesting period.

Taxes

CURRENT TAXES

Current taxes include federal capital tax which decreased to $1.9 million in 2005 from $2.5 million in 2004 (2003 - $2.5 million) due mainly to a tax rate reduction from 0.200% to 0.175%, as part of the phased elimination of federal capital tax by 2008.

Current taxes in 2005 also include $3.2 million related to the resolution of a Notice of Objection with respect to a corporate acquisition in a prior tax period. As a result of the reassessment resulting from resolution of the Notice of Objection, $7 million of tax deductible exploration expenses denied to the acquired corporation have been added to Compton's tax pools.

FUTURE INCOME TAXES

The Company's future income taxes were $52.3 million in 2005, compared to $33.4 million in 2004 and $20.0 million in 2003. Future taxes in 2004 benefited from an $8 million recovery due to a reduction in the Alberta tax rate from 12.5% to 11.5%. Future taxes in 2003 reflected a recovery of $37 million due to reductions in Canadian federal and Alberta corporate tax rates and related changes to the Canadian federal resource allowance and deductibility of provincial crown charges paid.

CORPORATE TAX RATES

Years ended December 31,	**2005**	2004	2003
Statutory rate	**37.6%**	38.6%	40.6%
Effective rate	**39.5%**	35.0%	16.4%

A reconciliation of the Company's effective tax rate to the statutory rate may be found in Note 15(a) to the consolidated financial statements.

TAX POOLS

The following table summarizes Compton's estimated tax pool balances by classification.

As at January 1, 2006	Available Balance ($000s)	Maximum Annual Deduction
Canadian exploration expense	$ 87,748	100%
Canadian development expense	322,165	30%
Canadian oil and natural gas property expense	217,203	10%
Undepreciated capital cost and financing costs	222,540	~25%
Total	$ 849,656	

A significant portion of the Company's taxable income is generated by a wholly owned partnership. Consolidated earnings before income taxes include $263 million (2004 - $178 million) of partnership earnings that will be included in the following year's income for income tax purposes. Future income taxes include $94 million (2004 - $67 million) as a result of this deferral of partnership earnings.

Based upon planned capital expenditure programs and current commodity price assumptions, it appears the Company will not be cash taxable until 2009.

Capital Expenditures

SUMMARY OF CAPITAL EXPENDITURE ALLOCATION

Years ended December 31,	2005 ($000s)	%	2004 ($000s)	%	2003 ($000s)	%
Drilling and completions	**$ 318,502**	62	$ 175,003	57	$ 126,308	57
Land and seismic	**55,469**	11	38,326	12	37,128	17
Facilities	**109,729**	21	68,861	23	46,068	21
Acquisitions, net	**28,575**	6	22,825	8	11,224	5
Sub-total	**512,275**	100	305,015	100	220,728	100
MPP	**1,261**		11,386		64,755	
Total capital expenditures	**$ 513,536**		$ 316,401		$ 285,483	

Capital Expenditures
($mm)

In 2005, Compton significantly increased its drilling program over that of previous years with the express objective of realizing on its unbooked resource potential. The Company drilled 334 net wells (392 gross) in 2005 as compared to 146 net wells (186 gross) in 2004. The number of net wells drilled in 2005 increased 129% over the number of net wells drilled in 2004. Reflecting this growth in activity, total 2005 capital expenditures, excluding MPP related expenditures, increased $207 million, or 68%, from $305 million in 2004 to $512 million in 2005.

As would be expected with the increased well count, 70% of the increase in capital expenditures relates to drilling and completion costs which increased $143 million from $175 million in 2004 to $319 million in 2005. On a per well basis, drilling and completion costs actually decreased 21% to an average of $0.95 million per net well in 2005 from an average of $1.2 million per net well in 2004. The decrease in the average cost per well reflects the Company's drilling focus during 2005. The Company's 2005 drill program included an additional 80 wells targeting Charlie Lake oil at Cecil and Worsley and an additional 110 wells targeting shallower Belly River gas in Southern Alberta as compared to 2004. These wells, and particularly the Belly River wells, are lower cost as compared to the deeper targets that comprise a greater percentage of the 2004 drill count.

Facility expenditures, which included processing facilities, gathering systems, compression and well equipment, comprised 21% of total capital expenditures and increased in relation to the Company's increased level of activity.

Strong commodity prices have accelerated capital programs and competition throughout the oil and gas industry, raising the demand and costs of land, drilling rigs, completion services, and supplies. During 2005, Compton experienced cost increases ranging as high as 20% for certain services over 2004 levels. In addition to the increased level of activity in 2005, capital expenditures for the year reflect this overall increase in the cost of goods and services.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, ($000s, except where noted)	**2005**	2004	2003
Working capital (1)	**$ 62,431**	$ 603	$ (21,843)
Bank debt	**177,900**	220,000	164,500
Senior term notes	**357,640**	198,594	213,246
Total indebtedness	**$ 597,971**	$ 419,197	$ 355,903
Capital stock	**$ 226,444**	$ 135,526	$ 131,577
Contributed surplus	**9,173**	3,840	760
Retained earnings	**360,719**	284,712	224,569
Shareholders' equity	**$ 596,336**	$ 424,078	$ 356,906
Debt to cash flow from operations (2) (3)	**1.93**	2.36	2.44
Debt to book capitalization (2)	**47%**	50%	51%
Debt to market capitalization (2)	**20%**	25%	35%

(1) Working capital excludes unrealized risk management items.

(2) Debt includes current and long term portion and excludes unrealized risk management items.

(3) Based on trailing 12 month cash flow from operations.

Working capital at December 31, 2005 decreased from the prior year due to the Company's extremely active fourth quarter and the resulting increase in trade payables. At year end, Compton had drawn $178 million on its available $289 million syndicated credit facility.

In November 2005, a wholly owned subsidiary of the Company issued U.S.$300 million of 7⅝% Senior Notes due in 2013. The proceeds were used to repay a portion of the Company's debt under its senior secured credit facilities and to fund the purchase of a portion of the 9.90% Senior Notes due in 2009, by a wholly owned subsidiary of the Company. At December 31, 2005, U.S.$6.75 million of the 9.90% Notes remain outstanding but can be called, at a premium, anytime after May 15, 2006. The purchase of the 9.90% Notes eliminated the restrictive covenants of the Indenture agreement and have provided the Company with greater financial flexibility.

The principal amount of the Senior Notes remains fixed at U.S. $300 million. The value of the notes reported on the consolidated balance sheets varies in response to movement in the Canadian/U.S. dollar exchange rate. Standards & Poor's Rating Services ("S&P") and Moody's Corporation ("Moody's") have rated the Company as B+ stable and B1 stable respectively, as at December 31, 2005. The U.S. $300 million 7⅝% Senior Notes are rated as B stable and B2 stable.

The Company expects internally generated operating cash flow together with other available financing options, including debt financing, readily accessible equity markets, and potential minor non-core property dispositions, will allow the Company to fund its planned 2006 capital program while maintaining fiscal responsibility.

Contractural Obligations

As part of normal business, Compton has entered into arrangements and incurred obligations that will impact our future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements.

The following table summarizes the Company's contractual obligations as at December 31, 2005.

($000s)	Payments Due by Period: Less than 1 year	1-3 years	4-5 years	After 5 years
Partnership distributions	$ 9,172	$ 21,401	$ –	$ –
Operating leases	11,277	7,418	–	–
Office rent	1,356	249	–	–
Senior Notes	–	7,870	–	349,770
Other	52	–	–	–
Total	$ 21,857	$ 36,938	$ –	$ 349,770

The Company has the ability and intends to extend the term of its current borrowings of $178 million on an ongoing basis under its syndicated credit facility and therefore repayment of the facility is not included in the schedule of contractual obligations above.

Commitments

To prevent the expiration of undeveloped lands, the Company anticipates $65 million of work commitments will be required in 2006. These commitments have been included in our 2006 capital expenditure budget.

GUIDANCE FOR 2006

Compton's 2006 budget was prepared in December 2005, and reflected commodity price forecasts at that time. With the recent decline in natural gas prices, the Company has reassessed its budget in relation to current prices. Current lower prices will reduce cash flow by approximately $80 million from that originally projected if sustained over the remainder of the year. At this juncture, the Company has not revised its drilling and capital programs.

In 2006, Compton will continue to focus on the development of its five natural gas resource plays and conventional crude oil property to maximize reserve recognition and production growth.

Summary of 2006 Guidance

	2006 Budget Range		
Capital expenditures ($millions)	$575		
Gross wells	480		
Average production			
Natural gas (MMcf/d)	155	to	160
Liquids (bbls/d)	11,000	to	11,300
Total (boe/d)	37,000	to	38,000
Cash flow from operations ($millions)	$375	to	$390

The Company's revised 2006 projected cash flow from operations projection is based upon the following pricing assumptions:

	Benchmark	Realized
Natural gas	AECO Cdn $7.90/GJ	Cdn $8.15/Mcf
Crude oil ($/bbl)	WTI U.S. $62.00	Cdn $65.00

The average Canadian/U.S. exchange rate is budgeted at $0.85 U.S. = $1.00 Cdn.

Cash Flow Sensitivities for 2006

($millions)		
Change of Cdn $0.10/Mcf in the benchmark AECO natural gas price	$	4.5
Change of U.S. $1.00/barrel in the benchmark WTI oil price	$	3.0

In the event of significant decreases in commodity prices, increases in exploration costs, or an overall economic downturn, the Company's capital expenditure program can be readily modified.

ADDITIONAL DISCLOSURES

Effectiveness of Disclosure Controls and Procedures

Compton has carried out an evaluation under the supervision and with the participation of its Management, including its President & CEO and VP Finance & CFO, of the effectiveness of the design and operation of the Company's disclosure controls and procedures. Based upon its evaluation, Compton has concluded that, as of December 31, 2005, the disclosure controls and procedures were effective in all material respects. The term "disclosure controls and procedures" is defined under the Security and Exchange Commission's Exchange Act Rule 13a-15(d) as controls and other procedures of a public company that are designed to ensure both non-financial and financial information required to be disclosed by the company in its periodic reports is recorded, processed, summarized, and reported in a timely fashion.

SARBANES OXLEY SECTION 404 UPDATE

Compton is required to comply with Section 404 of the Sarbanes Oxley Act of 2002. Section 404, together with the Security and Exchange Commission's Exchange Act and other Rules and Regulations, requires Compton to evaluate and certify its internal controls over financial reporting as at December 31, 2006, and have its evaluation and report thereto audited by its independent external auditors.

Compton has developed a plan for meeting these requirements and is working toward the execution of that plan. The Company is currently in the controls remediation phase of the plan and is confident it will meet all the requirements of Section 404 in the time required.

Accounting Estimates

Accounting estimates require Management to make assumptions regarding matters that are uncertain at the time the estimate is made and may have a material impact on the financial condition of the Company. A comprehensive discussion of Compton's significant accounting policies may be found in Note 1 to the consolidated financial statements.

OIL AND NATURAL GAS RESERVES

The independent petroleum engineering and geological consulting firm of Netherland Sewell evaluated and reported on 100% of Compton's oil and natural gas reserves.

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change with updated information from the results of future drilling, testing, or production levels. Such revisions could be upwards or downwards. Reserve estimates have a material impact on the depletion and depreciation, asset retirement obligations, and impairment costs, all of which could possibly have a material impact on consolidated net earnings.

DEPLETION

Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In 2005, Compton incurred $106 million of depletion and depreciation. If the proved reserves of the Company were to increase by 5%, the depletion and depreciation expense would decrease by $0.8 million and consolidated net earnings after tax would increase by $0.5 million. If the proved reserves of the Company were to decrease by 5%, the depletion and depreciation expense would increase by $1.9 million and consolidated net earnings after tax would decrease by $1.2 million.

IMPAIRMENT

In applying the full cost method of accounting, Compton periodically calculates a ceiling or limitation on the amount that property and equipment may be carried for on the consolidated balance sheets. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. As at December 31, 2005 the ceiling amount calculated was $2.5 billion in excess of the carrying value of the costs capitalized.

If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk free interest rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced as a result.

Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been discussed above. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainties. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long term price forecast and current operating costs per boe plus an inflation factor.

It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, it is not possible to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on impairment. No material downward revisions to the Company's reserves are anticipated.

ASSET RETIREMENT OBLIGATION

The Company recognizes the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long term assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long term assets. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings. Amounts recorded for asset retirement obligations are subject to uncertainty associated with the method, timing, and extent of future retirement activities. Actual payments to settle the obligations may differ from estimated amounts.

Risk Management

Compton's operations are subject to risks inherent to the oil and natural gas industry. The Company is exposed to financial risks including fluctuations in commodity prices, currency exchange rates, interest rates, credit ratings, and changing expenditure costs due to shifts in market conditions. The Company takes specific measures to manage these risks, particularly those that impact cash flow from operations.

A more detailed discussion of risk factors is presented in the Company's most recent Annual Information Form, filed with securities regulatory authorities on www.sedar.com.

COMMODITY PRICE RISK MANAGEMENT

Compton enters into commodity price contracts to manage risk associated with price volatility to protect cash flow from operations required to fund the Company's capital program. Commodity price risk is actively managed by using costless collars and by balancing physical and financial contracts in terms of volumes, timing of performance, and delivery obligations. Net open positions may exist or may be established to take advantage of market conditions. Net earnings for the year ended December 31, 2005 include realized and unrealized losses of $15 million (2004 - $7 million loss) on these transactions.

The following table outlines commodity hedge transactions which are currently outstanding.

Commodity	Term	Volume	Average Price	Index
Natural gas				
Collar	Nov. 2005 - Mar. 2006	40,000 GJ/d	Cdn$8.56 - $12.79	AECO
Fixed	Nov. 2005 - Mar. 2006	10,000 GJ/d	Cdn$8.60	AECO
Collar	Apr. 2006 - Oct. 2006	45,000 GJ/d	Cdn$8.33 - $12.23	AECO
Crude oil				
Collar	Jan. 2006 - Dec. 2006	3,000 bbls/d	U.S.$55.00 - $75.17	WTI

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

Compton is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Commodity prices are based on U.S. dollar benchmarks that result in Compton's realized price being influenced by the Canadian/U.S. currency exchange rate. Should the Canadian dollar strengthen compared to the U.S. dollar, the negative effect on net earnings would be partially offset by foreign exchange gains on the Company's U.S. dollar denominated Senior Notes. Conversely, should the Canadian dollar weaken compared to the U.S. dollar, the positive effect on net earnings would be partially offset by foreign exchange losses on the Company's U.S. dollar denominated Senior Notes. Cash flow from operations is not impacted by the effects of currency fluctuations on the Company's U.S. dollar denominated Senior Notes.

INTEREST RATE RISK MANAGEMENT

Concurrent with the closing of the Company's 9.90% Senior Notes offering in May of 2002, Compton entered into a cross currency interest rate swap. The swap, which converted fixed rate U.S. dollar interest obligations into floating rate Canadian dollar interest obligations, was entered into to fix the exchange rate on interest payments and take advantage of lower floating interest rates. On repurchase of the majority of 9.90% Senior Notes in November 2005, the Company elected not to collapse the swap and incur the associated costs of $12.2 million. The swap remains outstanding and at December 31, 2005 when the Company valued the liability relating to future unrealized losses on the swap arrangement to be $14.8 million (2004 - $11.4 million) determined on a mark-to-market basis. The loss associated with the swap has resulted

primarily from the strengthening of the Canadian dollar. Should the Canadian dollar continue to increase against the U.S. dollar, the loss could increase further; alternatively if the Canadian dollar were to weaken the loss would be reduced. Cash settlements of the swap positions are made semi-annually and losses realized will be recorded over the remaining term of the swap agreement which expires in May 2009.

Selected Quarterly Information

The following tables set out selected quarterly financial information of the Company for the last two fiscal years.

		Three Months Ended			Year Ended
($000s, except where noted)	**March 31, 2005**	**June 30, 2005**	**Sept. 30, 2005**	**Dec. 31, 2005**	**Dec. 31, 2005**
Average production (boe/d)	**28,714**	**28,877**	**29,041**	**31,042**	**29,424**
Average pricing ($/boe)	**$ 41.25**	**$ 46.33**	**$ 54.31**	**$ 64.58**	**$ 51.95**
Total revenue	**$ 106,589**	**$ 121,748**	**$ 145,114**	**$ 184,428**	**$ 557,879**
Cash flow from operations	**$ 52,277**	**$ 62,006**	**$ 74,189**	**$ 89,640**	**$ 278,112**
Per share: basic	**$ 0.43**	**$ 0.49**	**$ 0.58**	**$ 0.71**	**$ 2.21**
diluted	**$ 0.41**	**$ 0.47**	**$ 0.56**	**$ 0.67**	**$ 2.11**
Operating earnings	**$ 15,534**	**$ 18,923**	**$ 25,794**	**$ 33,413**	**$ 93,664**
Net earnings	**$ 10,059**	**$ 22,034**	**$ 11,127**	**$ 38,106**	**$ 81,326**
Per share: basic	**$ 0.08**	**$ 0.17**	**$ 0.09**	**$ 0.30**	**$ 0.65**
diluted	**$ 0.08**	**$ 0.17**	**$ 0.08**	**$ 0.28**	**$ 0.62**

Total revenue increased throughout 2005 as the result of high commodity prices and increasing production volumes. Average production increased in the third and fourth quarters, after abnormally wet weather in the summer restricted access in Southern Alberta resulting in flat production volumes in the second quarter. Quarterly net earnings fluctuated due to non-operational items such as unrealized risk management gains and losses and unrealized foreign exchange losses.

FOURTH QUARTER 2005

Average fourth quarter 2005 production increased 7% from the third quarter of 2005, with production in December 2005 reaching approximately 35,500 boe/d. Due to the abnormally wet weather in Southern Alberta during the summer months, well completions, tie-ins, and pipeline constructions were postponed until the fourth quarter. Revenue and net earnings for the quarter benefited from increased production and high commodity prices.

		Three Months Ended			Year Ended
($000s, except where noted)	March 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Dec. 31, 2004
Average production (boe/d)	25,717	26,295	27,268	28,204	26,876
Average pricing ($/boe)	$ 38.04	$ 41.43	$ 40.78	$ 39.00	$ 39.82
Total revenue	$ 89,031	$ 99,140	$ 102,299	$ 101,189	$ 391,659
Cash flow from operations	$ 40,860	$ 47,698	$ 46,844	$ 41,729	$ 177,131
Per share: basic	$ 0.35	$ 0.41	$ 0.40	$ 0.35	$ 1.51
diluted	$ 0.33	$ 0.39	$ 0.38	$ 0.33	$ 1.43
Operating earnings	$ 14,235	$ 15,428	$ 10,863	$ 6,359	$ 46,885
Net earnings	$ 22,301	$ 2,978	$ 21,977	$ 16,377	$ 63,633
Per share: basic	$ 0.19	$ 0.03	$ 0.19	$ 0.14	$ 0.54
diluted	$ 0.18	$ 0.02	$ 0.18	$ 0.13	$ 0.51

In 2004, strong overall commodity prices and increasing production improved total revenue on a quarterly basis. Average production in 2004 grew as a result of the Company's ongoing drilling program and the resolution of facility and pipeline restrictions in Southern Alberta. Net earnings in the second quarter of 2004 was impacted by an unrealized risk management loss of $7 million after tax and an unrealized foreign exchange loss of $4 million after tax. Net earnings in the first, third, and fourth quarters in 2004 benefited from unrealized risk management gains.

Selected Annual Information

Years ended December 31, ($000s)	**2005**	2004	2003
Total revenue	**$ 557,879**	$ 391,659	$ 346,565
Net earnings	**$ 81,326**	$ 63,633	$ 118,880
Per share: basic	**$ 0.65**	$ 0.54	$ 1.02
diluted	**$ 0.62**	$ 0.51	$ 0.97
Total assets	**$ 1,755,489**	$ 1,330,611	$1,064,320
Total long term financial liabilities	**$ 535,540**	$ 198,594	$ 213,246

Total revenue in 2005 was higher than in the two previous years due to a combination of increased production and higher commodity prices. Net earnings in 2005 increased $18 million, 28%, from 2004 and were reduced by non-recurring one-time costs of $14.4 million ($20.8 million before taxes) relating to the repurchase of U.S.$158.25 million of 9.90% Senior Notes.

Total assets increased from the prior year primarily due to capital expenditures of $514 million. The change in long term financial liabilities at December 31, 2005 resulted from the Company issuing U.S.$300 million Senior Notes and reclassifying bank debt as long term.

Net earnings in 2004 decreased from the prior year as 2003 benefited from a $38 million after tax unrealized foreign exchange gain on the Company's U.S. dollar denominated debt and a $37 million recovery of future income taxes relating to statutory income tax rate changes.

Total assets were $1.3 billion at December 31, 2004, an increase of 25% from the prior year due to capital expenditures of $316 million. The change in long term financial liabilities at December 31, 2004 resulted from an unrealized gain due to the translation of the Company's U.S. $165 million Senior Notes.

Trading and Share Statistics

As at March 15, 2006 there were 127,272,451 common shares outstanding, including 12,505,627 stock options outstanding.

	2005	2004	2003
Average daily trading volume (000s)	**736,416**	674,764	686,100
Share price ($/share)			
High	**$ 18.66**	$ 11.43	$ 6.35
Low	**$ 9.80**	$ 5.89	$ 4.40
Close	**$ 17.10**	$ 10.85	$ 6.00
Market capitalization at December 31 ($000s)	**$ 2,176,205**	$ 1,273,282	$ 698,535
Shares outstanding (000s)	**127,263**	117,354	116,423

FURTHER INFORMATION

Additional information about Compton, including the Company's Annual Information Form, is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Forward Looking Statements

Certain information regarding the Company contained herein constitutes forward looking statements under the meaning of applicable securities laws, including the United States Private Securities Litigation Reform Act of 1995. Forward looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact, including statements regarding (i) cash flow, production, capital expenditures and planned wells in 2006, and (ii) other risks and uncertainties described from time to time in the reports and filings made by Compton with securities regulatory authorities. Although Compton believes that the expectations reflected in such forward looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward looking statements not to be correct, including risks and uncertainties inherent in the Company business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards and mechanical failures, uncertainties in the estimates of reserves and in projections of future rates of production and timing of development expenditures, general economic conditions, the actions or inactions of third party operators and regulatory pronouncements. Compton may, as considered necessary in the circumstances, update or revise forward looking information, whether as a result of new information, future events, or otherwise. The Company's forward looking statements are expressly qualified in their entirety by this cautionary statement.

Non-GAAP Financial Measures

Included in the MD&A and elsewhere in this report are references to terms used in the oil and gas industry such as cash flow from operations, cash flow per share and operating earnings. These terms are not defined by GAAP in Canada and consequently are referred to as non-GAAP measures. Non-GAAP measures do not have any standardized meaning and therefore reported amounts may not be comparable to similarly titled measures reported by other companies.

Cash flow from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with Canadian GAAP, as an indicator of the Company's performance or liquidity. Cash flow from operations is used by Compton to evaluate operating results and the Company's ability to generate cash to fund capital expenditures and repay debt.

Operating earnings represents net earnings excluding certain items that are largely non-operational in nature and should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with Canadian GAAP. Operating earnings is used by the Company to facilitate comparability of earnings between periods.

Use of BOE Equivalents

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Compton has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boes do not represent a value equivalency at the plant gate where Compton sells its production volumes and therefore may be a misleading measure if used in isolation.

Management's Report

TO THE SHAREHOLDERS OF COMPTON PETROLEUM CORPORATION

The accompanying consolidated financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of Management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the consolidated financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these consolidated financial statements.

The Audit, Finance and Risk Committee of the Board of Directors has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit, Finance and Risk Committee.

E.G. Sapieha, C.A.
President & Chief Executive Officer

N.G. Knecht, C.A
Vice President Finance & Chief Financial Officer

March 13, 2006

Independent Auditors' Report

TO THE SHAREHOLDERS OF COMPTON PETROLEUM CORPORATION

We have audited the accompanying consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings, and cash flow in the three year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and cash flow for the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principles vary in certain significant respects from accounting principles generally accepted in the United States of America. Information relating to the nature and effect of such differences are presented in Note 19 to the consolidated financial statements.

Grant Thornton LLP

Chartered Accountants

Calgary, Alberta, Canada
March 13, 2006

Consolidated Balance Sheets

As at December 31, (thousands of dollars)		2005	2004
Assets			
Current			
Cash		$ 8,954	$ 10,068
Accounts receivable and other		132,484	115,113
Unrealized risk management gain	Note 16a (i)	–	1,985
		141,438	127,166
Property and equipment	Note 4	1,587,371	1,178,550
Goodwill	Note 2	7,914	7,914
Deferred financing charges and other	Note 8	13,156	9,729
Deferred risk management loss	Note 16a (ii)	5,610	7,252
		$1,755,489	$1,330,611
Liabilities			
Current			
Bank debt	Note 5	$ –	$ 220,000
Accounts payable		203,869	125,483
Unrealized risk management loss	Note 16a (i)	3,150	–
Income taxes payable		–	301
		207,019	345,784
Bank debt	Note 5	177,900	–
Senior term notes	Note 6	357,640	198,594
Asset retirement obligations	Note 10	20,770	18,006
Unrealized risk management loss	Note 16a (iii)	14,809	11,416
Future income taxes	Note 15b	312,117	261,196
Non-controlling interest	Note 3	68,898	71,537
		1,159,153	906,533
Shareholders' equity			
Capital stock	Note 11b	226,444	135,526
Contributed surplus	Note 12a	9,173	3,840
Retained earnings		360,719	284,712
		596,336	424,078
		$1,755,489	$1,330,611
Commitments and contingent liabilities	Note 18		

On behalf of the Board

M.F. Belich
Director

J.A. Thomson
Director

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Earnings

Years ended December 31, (thousands of dollars, except per share data)		2005	2004	2003
Revenue				
Oil and natural gas revenues		$ 557,879	$ 391,659	$ 346,565
Royalties		(132,717)	(93,416)	(82,566)
		425,162	298,243	263,999
Expenses				
Operating		66,802	55,655	49,916
Transportation		10,858	8,595	8,447
General and administrative		21,223	15,215	12,206
Interest and finance charges	Note 7	34,951	33,733	30,595
Tender costs	Note 8	20,750	–	–
Depletion and depreciation		105,504	82,554	61,749
Foreign exchange gain	Note 9	(7,353)	(14,631)	(47,368)
Accretion of asset retirement obligations	Note 10	1,975	1,670	1,436
Stock-based compensation	Note 12a	5,903	3,410	793
Risk management loss	Note 16a (iv)	19,302	8,808	4,132
		279,915	195,009	121,906
Earnings before taxes and non-controlling interest		145,247	103,234	142,093
Income taxes	Note 15a			
Current		5,071	2,751	3,282
Future		52,317	33,432	20,041
		57,388	36,183	23,323
Earnings before non-controlling interest		87,859	67,051	118,770
Non-controlling interest	Note 3	6,533	3,418	(110)
Net earnings		$ 81,326	$ 63,633	$ 118,880
Net earnings per share	Note 13			
Basic		$ 0.65	$ 0.54	$ 1.02
Diluted		$ 0.62	$ 0.51	$ 0.97

Consolidated Statements of Retained Earnings

Years ended December 31, (thousands of dollars)		2005	2004	2003
Retained earnings, beginning of year		$ 284,712	$ 224,569	$ 112,039
Net earnings		81,326	63,633	118,880
Premium on redemption of shares	(Note 11b)	(5,319)	(3,490)	(6,350)
Retained earnings, end of year		$ 360,719	$ 284,712	$ 224,569

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flow

Years ended December 31, (thousands of dollars)		**2005**	2004	2003
Operating activities				
Net earnings		**$ 81,326**	$ 63,633	$ 118,880
Amortization of deferred charges and other		**2,190**	2,101	2,208
Tender costs		**20,750**	–	–
Depletion and depreciation		**105,504**	82,554	61,749
Accretion of asset retirement obligations		**1,975**	1,670	1,436
Unrealized foreign exchange gain		**(7,808)**	(14,652)	(47,388)
Future income taxes		**52,317**	33,432	20,041
Unrealized risk management loss		**10,171**	2,179	–
Stock-based compensation		**5,903**	3,410	760
Asset retirement expenditures		**(749)**	(614)	(2,683)
Non-controlling interest		**6,533**	3,418	(110)
		278,112	177,131	154,893
Change in non-cash working capital	*Note 17*	**8,441**	(12,594)	1,318
		286,553	164,537	156,211
Financing activities				
Issuance (repayment) of bank debt		**(42,100)**	43,373	124,500
Issuance of senior notes		**353,130**	–	–
Issue costs on senior notes		**(12,670)**	–	(128)
Redemption of senior notes		**(199,973)**	–	–
Proceeds from share issuances, net		**89,752**	3,258	6,400
Proceeds from partnership unit issuance		**–**	74,343	–
Distributions to partner		**(9,172)**	(6,114)	–
Redemption of common shares		**(6,118)**	(4,005)	(7,942)
Change in non-cash working capital	*Note 17*	**(1,829)**	324	(1,387)
		171,020	111,179	121,443
Investing activities				
Property and equipment additions		**(484,213)**	(296,676)	(222,055)
Corporate acquisitions	*Note 2*	**–**	(12,132)	–
Property acquisitions		**(28,575)**	(20,830)	(65,622)
Property dispositions		**–**	19,276	2,194
Change in non-cash working capital	*Note 17*	**54,101**	29,166	8,652
		(458,687)	(281,196)	(276,831)
Change in cash		**(1,114)**	(5,480)	823
Cash, beginning of year		**10,068**	15,548	14,725
Cash, end of year		**$ 8,954**	$ 10,068	$ 15,548

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 2005

(Tabular amounts in thousands of dollars, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

Compton Petroleum Corporation (the "Company" or "Compton") is in the business of the exploration for and production of petroleum and natural gas reserves in the Western Canada Sedimentary Basin.

a) Basis of presentation

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada within the framework of the accounting policies summarized below. Information prepared in accordance with accounting principles generally accepted in the United States is included in Note 19.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The consolidated financial statements also include the accounts of Mazeppa Processing Partnership in accordance with Accounting Guideline 15 ("AcG-15") "Consolidation of Variable Interest Entities", as outlined in Note 3.

All amounts are presented in Canadian dollars unless otherwise stated.

b) Measurement uncertainty

The timely preparation of financial statements requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The calculation of asset retirement obligations include estimates of the ultimate settlement amounts, inflation factors, credit adjusted discount rates, and timing of settlement. The impact of future revisions to these assumptions on the consolidated financial statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

c) Property and equipment

i) CAPITALIZED COSTS

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both producing and non-producing wells, production facilities, asset retirement costs and certain general and administrative expenses directly related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are included in property and equipment when incurred and charged to depletion and depreciation in the consolidated statement of earnings over the estimated period of time to the next scheduled turnaround.

ii) DEPLETION AND DEPRECIATION

Depletion and depreciation of property and equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred. Estimated future costs to be incurred in developing proved reserves are included in costs subject to depletion. For depletion and depreciation purposes, relative volumes of natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of certain midstream facilities is provided for on a straight line basis over 30 years and depreciation of office equipment is provided for on a declining balance basis at 20% per year.

iii) IMPAIRMENT TEST

At each reporting period the Company performs an impairment test to determine the recoverability of capitalized costs associated with reserves. An impairment loss is recognized when the carrying amount of a cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves plus the costs of unproved properties. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

iv) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs are amortized using the unit-of-production method and are included in depletion and depreciation in the consolidated statement of earnings. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings.

Actual expenditures incurred are charged against the accumulated obligation.

v) INVENTORIES

Physical inventory held for exploration, development, and operating activities is included in property and equipment and is valued at cost.

d) Goodwill

Goodwill is recorded on a corporate acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed at least annually to evaluate the carrying value. To assess impairment the fair value of the consolidated entity, excluding the Mazeppa Processing Partnership, is determined and compared to the carrying value. If fair value is less than the carrying value then a second test is performed to determine the amount of the impairment. Any loss recognized is equal to the difference between the implied fair value and the carrying value of the goodwill.

e) Financial instruments

Financial instruments consist mainly of accounts receivable and other, accounts payable, and long-term debt. The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates, and interest rates as described in Note 16. The Company has elected not to designate any of its current risk management activities as accounting hedges and accounts for all derivative financial instruments using the mark-to-market accounting method.

f) Joint operations

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

g) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. The liability for future income taxes is increased and capital stock is reduced by the estimated tax benefits transferred to shareholders at the time the resource expenditure deductions are renounced.

h) Earnings per share amounts

The Company uses the treasury stock method to determine the dilutive effect of stock options. This method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the period. Basic net earnings per common share are determined by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by giving effect to the potential dilution that would occur if stock options were exercised.

i) Income taxes

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Changes in income tax rates that are substantively enacted are reflected in the accumulated future income tax balances in the period the change occurs.

j) Revenue recognition

Revenue associated with the production and sale of crude oil, natural gas, and natural gas liquids owned by the Company is recognized when the purchaser takes possession of the commodity product. Other revenue is recognized in the period that the service is provided to the customer.

k) Stock-based compensation plan

The Company records compensation expense in the consolidated statements of earnings for stock options granted to Directors, Officers, and employees using the fair-value method. Compensation costs are recognized over the vesting period and the fair values are determined using the Black-Scholes option pricing model.

The Company also has an employee stock savings plan. The contributions are recorded as compensation expense as incurred.

l) Deferred financing charges

Financing costs related to the issuance of senior term notes are deferred and are amortized over the term of the notes on a straight-line basis. If the notes are retired, in whole or in part, prior to maturity, a pro-rata share of the unamortized balance is expensed in the consolidated statement of earnings.

m) Foreign currency translation

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into Canadian dollars at the period-end exchange rate, with any resulting gain or loss recorded in the consolidated statement of earnings.

n) Dividend policy

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

o) Defined benefit pension plan

The Company accrues for obligations under a defined benefit pension plan and the related costs, net of plan assets. The cost of the pension is actuarially determined using the projected benefit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation, and retirement age of employees.

2. BUSINESS COMBINATIONS

On April 12, 2004 and November 15, 2004, respectively, the Company acquired 100% of the issued and outstanding shares of Redwood Energy, Ltd. and Mayfair Energy Ltd. for total cash consideration of $12.1 million plus the assumption of $12.1 million of debt. Both entities were independent exploration and production companies with operations in the Company's core areas.

The business combinations have been accounted for using the purchase method with results of operations included in the consolidated financial statements from the date of acquisition. Goodwill recognized on these transactions amounted to $7.9 million.

During the year ended December 31, 2004, both companies were wound up into Compton Petroleum Corporation and dissolved.

3. NON-CONTROLLING INTEREST

Mazeppa Processing Partnership ("MPP" or "the Partnership") is a limited partnership organized under the laws of the province of Alberta and owns certain midstream facilities, including gas plants and pipelines in Southern Alberta. The Company processes a significant portion of its production from the area through these facilities pursuant to a processing agreement with MPP. The Company does not have an ownership position in MPP, however, the Company, through a management agreement, manages the activities of MPP and is considered to be the primary beneficiary of MPP's operations. Pursuant to AcG-15, these consolidated financial statements include the assets, liabilities, and operations of the Partnership. Equity in the Partnership, attributable to the partners of MPP, is recorded on consolidation as a non-controlling interest and is comprised of the following:

As at December 31,	**2005**	2004
Non-controlling interest, beginning of year	**$ 71,537**	$ (110)
Proceeds from issue of Partnership units, net	**–**	74,343
Earnings attributable to non-controlling interest	**6,533**	3,418
Distributions to limited partner	**(9,172)**	(6,114)
Non-controlling interest, end of year	**$ 68,898**	$ 71,537

Commencing May 1, 2004, pursuant to the terms of a processing agreement between Compton and MPP, Compton pays a monthly fee to MPP for the transportation and processing of natural gas through the MPP owned facilities. The fee is comprised of a fixed base fee of $764 thousand per month plus MPP operating costs, net of third party revenues. These amounts are eliminated from revenues and expenses on consolidation.

The processing agreement has a five year term ending April 1, 2009, at which time Compton may renew the agreement under terms determined at that time or purchase the Partnership units for the predetermined amount of $55 million, deemed to be fair value. In the event that the Company does not renew the processing agreement nor exercise the purchase option, the Limited Partner may dispose of the Partnership units to an independent third party.

MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. The maximum liability of the Partnership under the guarantee is limited to amounts due and payable to MPP by the Company pursuant to the processing agreement. The maximum liability at December 31, 2005 was $30.6 million (2004 - $39.7 million) payable over the remaining term of the processing agreement. The Company has determined that its exposure to loss under these arrangements is minimal, if any.

4. PROPERTY AND EQUIPMENT

As at December 31, 2005	**Cost**	**Accumulated depletion and depreciation**	**Net**
Exploration and development costs	**$ 1,553,543**	**$ (366,902)**	**$ 1,186,641**
Production equipment and processing facilities	**436,948**	**(52,771)**	**384,177**
Inventory	**6,469**	**–**	**6,469**
Future asset retirement costs	**10,365**	**(3,771)**	**6,594**
Office equipment	**7,641**	**(4,151)**	**3,490**
	$ 2,014,966	**$ (427,595)**	**$ 1,587,371**

As at December 31, 2004	Cost	Accumulated depletion and depreciation	Net
Exploration and development costs	$ 1,161,396	$ (281,614)	$ 879,782
Production equipment and processing facilities	317,477	(34,150)	283,327
Inventory	6,187	–	6,187
Future asset retirement costs	9,576	(3,111)	6,465
Office equipment	6,005	(3,216)	2,789
	$ 1,500,641	$ (322,091)	$1,178,550

Employee salaries and insurance costs of $4.7 million at December 31, 2005 (2004 - $4.6 million) directly related to exploration and development activities were capitalized. No other general and administrative costs are capitalized.

As at December 31, 2005 future capital expenditures of $192.9 million (2004 - $89.1 million, 2003 - $62.4 million), as estimated by independent reserve engineers, relating to the development of proved reserves have been included in costs subject to depletion. Undeveloped properties with a cost at December 31, 2005 of $251.3 million (2004 - $187.8 million, 2003 - $161.9 million) included in exploration and development costs, have not been subject to depletion.

The prices used in the evaluation of the carrying value of the Company's reserves for the purposes of the impairment test are:

As at December 31, 2005	Natural gas $ per Mcf	Oil $ per bbl	NGL $ per bbl
2006	$ 11.86	$ 61.58	$ 61.87
2007	$ 10.76	$ 60.97	$ 61.64
2008	$ 9.16	$ 57.38	$ 58.19
2009	$ 8.33	$ 54.11	$ 55.05
2010	$ 8.09	$ 51.85	$ 52.58
Approximate % increase thereafter	2%	2%	2%

5. CREDIT FACILITIES

As at December 31,	**2005**	2004
Authorized	**$ 289,000**	$ 240,000
Prime rate	**$ 22,900**	$ 3,000
Bankers' Acceptance	**155,000**	217,000
Utilized	**$ 177,900**	$ 220,000

As at December 31, 2005, the Company had arranged authorized senior credit facilities with a syndicate of Canadian banks in the amount of $289 million. Advances under the facilities can be drawn and currently bear interest as follows:

Prime rate plus 0.15%
Bankers' Acceptance rate plus 1.15%
LIBOR rate plus 1.15%

Margins are determined based on the ratio of total consolidated debt to consolidated cash flow. The facilities reach term on July 5, 2006, and if not renewed, will mature 366 days later on July 6, 2007. Accordingly, the 2005 facilities have been classified as a non-current liability.

The senior credit facilities are secured by a first fixed and floating charge debenture in the amount of $600 million covering all the Company's assets and undertakings.

6. SENIOR TERM NOTES

As at December 31,	2005	2004
Senior term notes		
U.S. $300 million, 7.625% due December 1, 2013	**$ 349,770**	$ –
U.S. $6.75 million, 9.90% due May 15, 2009 (2004 - U.S. $165 million)	**7,870**	198,594
	$ 357,640	$ 198,594

In November 2005, a wholly owned subsidiary of the Company issued U.S. $300 million senior term notes maturing December 1, 2013. The notes bear interest at 7.625% and are subordinate to the Company's bank credit facilities.

The 7.625% notes are not redeemable prior to December 1, 2009, except in limited circumstances. After that time, they can be redeemed in whole or part, at the rates indicated below:

December 1, 2009	103.813%
December 1, 2010	101.906%
December 1, 2011 and thereafter	100.000%

In November 2005, the Company and a wholly owned subsidiary of the Company completed a tender offer and consent solicitation to amend the Indenture relating to the 9.90% notes. The Company and a wholly owned subsidiary of the Company paid 107.195% plus accrued and unpaid interest for the U.S. $158.25 million 9.90% notes tendered by the note holders. Information related to the tender costs is included in Note 8.

The remaining U.S. $6.75 million of 9.90% notes are not redeemable prior to May 15, 2006. After that time, they can be redeemed in whole or part, at the rates indicated below:

May 15, 2006	104.950%
May 15, 2007	102.475%
May 15, 2008 and thereafter	100.000%

7. INTEREST AND FINANCE CHARGES

Amounts charged to expense during the year ended are as follows:

Years ended December 31,	2005	2004	2003
Interest on bank debt, net	**$ 11,520**	$ 9,662	$ 6,611
Interest on senior term notes	**20,912**	21,281	21,711
Finance charges	**2,519**	2,790	2,273
Total	**$ 34,951**	$ 33,733	$ 30,595

Finance charges include the amortization of deferred charges and other current year expenses.

8. DEFERRED FINANCING CHARGES AND OTHER

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of deferred financing charges associated with the issue of senior term notes:

Years ended December 31	**2005**	2004
Deferred financing charges and other, beginning of year	**$ 9,729**	$ 11,532
Issue costs on 7.625% Senior Notes	**12,670**	–
Pro-rata reduction on repayment of 9.90% Senior Notes	**(7,053)**	–
Amortization expense	**(2,119)**	(2,133)
Other	**(71)**	330
Deferred financing charges and other, end of year	**$ 13,156**	$ 9,729

Costs incurred on the tender for the 9.90% senior term notes in 2005 were as follows:

Premium payment	**$ 7,814**
Consent solicitation fee	**5,883**
Pro-rata reduction of deferred financing charges on repayment of 9.90% Senior Notes	**7,053**
Total	**$ 20,750**

9. FOREIGN EXCHANGE (GAIN) LOSS

Amounts charged to foreign exchange (gain) loss during the year ended were as follows:

Years ended December 31,	**2005**	2004	2003
Foreign exchange gain on translation of U.S. $ debt	**$ (7,808)**	$ (14,652)	$ (47,388)
Other foreign exchange loss	**455**	21	20
Total	**$ (7,353)**	$ (14,631)	$ (47,368)

10. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and natural gas assets:

As at December 31	**2005**	2004
Asset retirement obligations, beginning of year	**$ 18,006**	$ 17,329
Liabilities incurred	**5,218**	3,357
Liabilities settled and disposed	**(1,275)**	(4,350)
Accretion expense	**1,975**	1,670
Revision of estimates	**(3,154)**	–
Asset retirement obligations, end of year	**$ 20,770**	$ 18,006

The total undiscounted amount of estimated cash flows required to settle the obligations was $185.8 million (2004 - $148.9 million), which has been discounted using a credit-adjusted risk free rate of 10.7% (2004 - 10.8%). The majority of these obligations are not expected to be settled for several years or decades into the future. Settlements will be funded from general Company resources at the time of retirement and removal.

11. CAPITAL STOCK

a) *Authorized*

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series.

b) *Issued and outstanding*

	2005		2004	
As at December 31,	**Number of Shares (000s)**	**Amount**	Number of Shares (000s)	Amount
Common shares outstanding, beginning of year	**117,354**	**$ 135,526**	116,423	$ 131,577
Shares issued for cash, net	**7,500**	**87,294**	–	–
Shares issued for property	**–**	**–**	110	875
Shares issued under stock option plan	**2,926**	**4,424**	1,271	3,589
Shares repurchased	**(517)**	**(800)**	(450)	(515)
Common shares outstanding, end of year	**127,263**	**$ 226,444**	117,354	$ 135,526

In February 2005, the Company issued 7,500,000 common shares for gross proceeds of $90.0 million before underwriters' fees and issue expenses of $4.1 million.

The Company maintains a Normal Course Issuer Bid program on an annual basis. Under the current bid, the Company may purchase for cancellation up to 6,000,000 of its common shares, representing approximately 5.0% of the issued and outstanding common shares at the time the bid received regulatory approval.

During the year, the Company purchased for cancellation 516,600 common shares at an average price of $11.84 per share (2004 - 450,100 common shares at an average price of $8.90 per share) pursuant to the normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

c) *Shareholder rights plan*

The Company has a shareholder rights plan (the "Plan") to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire common shares at a 50% discount to the market price at that time.

12. STOCK-BASED COMPENSATION PLANS

a) *Stock option plan*

The Company has implemented a stock option plan for Directors, Officers, and employees. The exercise price of each option approximates the market price for the common shares on the date the option was granted. Options granted under the plan before June 1, 2003 are generally fully exercisable after four years and expire ten years after the grant date. Options granted under the plan after June 1, 2003 are generally fully exercisable after four years and expire five years after the grant date.

The following tables summarize the information relating to stock options:

	2005		2004	
As at December 31,	**Stock Options (000s)**	Weighted Average Exercise **Price**	Stock Options (000s)	Weighted Average Exercise Price
Outstanding, beginning of year	**11,655**	**$ 3.51**	10,672	$ 2.54
Granted	**2,930**	**$ 11.89**	2,549	$ 7.34
Exercised	**(2,926)**	**$ 1.32**	(1,271)	$ 2.56
Cancelled	**(213)**	**$ 8.30**	(295)	$ 5.26
Outstanding, end of year	**11,446**	**$ 6.13**	11,655	$ 3.51
Exercisable, end of year	**6,219**	**$ 3.38**	7,812	$ 2.19

The range of exercise prices of stock options outstanding and exercisable at December 31, 2005 were as follows:

	Outstanding Options			**Exercisable Options**	
Range of exercise prices	Number of options outstanding (000s)	Weighted average remaining contractual life (years)	Weighted average exercise price	Number of options outstanding (000s)	Weighted average exercise price
$0.80 - $2.99	2,644	2.7	$ 1.55	2,644	$ 1.55
$3.00 - $3.99	1,509	5.3	$ 3.47	1,279	$ 3.40
$4.00 - $4.99	1,598	6.1	$ 4.30	1,215	$ 4.24
$5.00 - $6.99	1,188	2.9	$ 5.87	597	$ 5.88
$7.00 - $9.99	1,485	3.4	$ 7.62	427	$ 7.62
$10.00 - $12.99	2,690	4.2	$ 11.58	42	$ 10.60
$13.00 - $17.38	332	4.7	$ 13.70	15	$ 13.44
	11,446	4.1	$ 6.13	6,219	$ 3.38

The Company has recorded stock-based compensation expense in the consolidated statement of earnings for stock options granted to Directors, Officers, and employees after January 1, 2003 using the fair value method.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Years ended December 31,	**2005**	2004	2003
Weighted average fair value of options granted	**$ 5.45**	$ 3.70	$ 3.01
Risk-free interest rate	**3.6%**	3.9%	4.3%
Expected life (years)	**5.0**	5.0	6.1
Expected volatility	**43.9%**	49.6%	56.0%

The following table presents the reconciliation of contributed surplus with respect to stock-based compensation:

As at December 31	**2005**	2004
Contributed surplus, beginning of year	**$ 3,840**	$ 760
Stock-based compensation expense	**5,903**	3,410
Stock options exercised	**(570)**	(330)
Contributed surplus, end of year	**$ 9,173**	$ 3,840

The Company has not recorded stock-based compensation expense in the consolidated statement of earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, the effect would have been as follows:

Years ended December 31,	**2005**	2004	2003
Reduction in net earnings	$ **1,007**	$ 1,545	$ 2,317
Reduction in net earnings per common share - basic and diluted	$ **0.01**	$ 0.01	$0.02

b) *Share appreciation rights plan*

CICA Handbook section 3870 requires recognition of compensation costs with respect to changes in the intrinsic value for the variable component of fixed share appreciation rights ("SARs"). During the years ended December 31, 2005 and 2004, there were no significant compensation costs related to the outstanding variable component of these SARs, (2003 - $33,000). The liability related to the variable component of these SARs amounts to $1.4 million, which is included in accounts payable as at December 31, 2005 (2004 - $1.7 million). All outstanding SARs having a variable component expire at various times through 2011.

13. PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share:

Years ended December 31,	**2005 (000s)**	2004 (000s)	2003 (000s)
Weighted average common shares outstanding - basic	**125,627**	117,244	116,267
Effect of stock options	**6,040**	6,789	5,856
Weighted average common shares outstanding - diluted	**131,667**	124,033	122,123

In calculating diluted earnings per common share for the year ended December 31, 2005, the Company excluded 331,800 options (2004 - 288,000, 2003 - 615,100) as the exercise price was greater than the average market price of its common shares in those years.

14. DEFINED BENEFIT PENSION PLAN

Substantially all of the employees of MPP are enrolled in a co-sponsored, defined benefit pension plan. The Company does not have a pension plan for other employees. Information relating to the MPP retirement plan is outlined below:

As at December 31	**2005**	2004
Accrued benefit obligation	$ **7,562**	$ 5,855
Fair value of plan assets	$ **5,839**	$ 5,221
Funded status		
Plan assets less than benefit obligation	$ **(1,723)**	$ (634)
Unamortized net actuarial loss (gain)	**891**	(269)
Unamortized past service costs	**862**	933
Accrued benefit asset, included in deferred financing charges and other	$ **30**	$ 30

Economic assumptions used to determine benefit obligation and periodic expense were:

Years ended December 31,	**2005**	2004
Discount rate	**5.0%**	6.3%
Expected rate of return on assets	**7.0%**	7.0%
Rate of compensation increase	**3.5%**	4.5%
Average remaining service period of covered employees	**15 years**	15 years

Actuarial evaluations are required every three years, the next evaluation being January 1, 2006.

Pension expense, included in MPP operating costs, is as follows:

Years ended December 31,	**2005**	2004
Current service cost	**$ 232**	$ 190
Interest on accrued benefit obligation	**372**	336
Interest on assets	**(364)**	(333)
Amortization on past service cost	**69**	67
Pension expense, included in general and administrative expense	**$ 309**	$ 260

MPP expects to contribute $340 thousand to the plan in 2006. Contributions by the participants to the pension plan were $75 thousand for the year ended December 31, 2005.

15. INCOME TAXES

a) The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

Years ended December 31,	**2005**	2004	2003
Earnings before taxes and non-controlling interest	**$ 145,247**	$ 103,234	$ 142,093
Canadian statutory rate	**37.6%**	38.6%	40.6%
Expected income taxes	**$ 54,613**	$ 39,848	$ 57,690
Effect on taxes resulting from:			
Non-deductible Crown charges	**15,061**	17,611	23,922
Resource allowance	**(11,980)**	(13,535)	(16,485)
Non-deductible stock-based compensation	**2,221**	1,316	309
Federal capital tax	**1,896**	2,526	2,497
Effect of tax rate changes	**(5,764)**	(8,359)	(37,130)
Non-taxable portion of capital items	**-**	(2,831)	(8,202)
Other	**1,341**	(393)	722
Provision for income taxes	**$ 57,388**	$ 36,183	$ 23,323
Current			
Income taxes	**$ 3,175**	$ 225	$ 785
Federal capital taxes	**1,896**	2,526	2,497
Future	**52,317**	33,432	20,041
	$ 57,388	$ 36,183	$ 23,323
Effective tax rate	**39.5%**	35.0%	16.4%

A significant portion of the Company's taxable income is generated by a partnership. Income taxes are incurred on the majority of the partnership's taxable income in the year following its inclusion in the Company's consolidated net earnings. Current income tax is dependent upon the amount of capital expenditures incurred and the method of deployment.

b) The net future income tax liability is comprised of:

As at December 31	**2005**	2004
Future income tax liabilities		
Property and equipment in excess of tax values	**$ 232,258**	$ 199,931
Timing of partnership items	**93,532**	67,089
Foreign exchange gain on long-term debt	**11,466**	10,169
Future income tax assets		
Attributed Canadian royalty income	**(8,830)**	(9,015)
Asset retirement obligations	**(6,984)**	(6,057)
Other	**(9,325)**	(921)
Net future income tax liability	**$ 312,117**	$ 261,196

16. FINANCIAL INSTRUMENTS

a) Derivative financial instruments and risk management activities

The Company is exposed to risks from fluctuations in commodity prices, interest rates, and Canada/U.S. currency exchange rates. The Company utilizes various derivative financial instruments for non-trading purposes to manage and mitigate its exposure to these risks. Effective January 1, 2004, the Company elected to account for all derivative financial instruments using the mark-to-market method.

Risk management activities during the periods, utilizing derivative instruments, relate to commodity price hedges and cross currency interest rate swap arrangements and are summarized below:

i) COMMODITY PRICE HEDGES

The Company enters into hedge transactions relating to crude oil and natural gas prices to mitigate volatility in commodity prices and the resulting impact on cash flow. The contracts entered into are forward transactions providing the Company with a range of prices on the commodities sold. Outstanding hedge contracts at December 31, 2005 are:

Commodity	Term	Daily Notional Volume	Average Price	Mark-to-Market gain (loss)
Natural gas				
Collar	Nov. 1/05 - Mar. 31/06	38,095 Mcf	$8.70 - $12.74/Mcf	$ (929)
Fixed	Nov. 1/05 - Mar. 31/06	9,524 Mcf	$9.03/Mcf	(1,735)
Collar	Apr. 1/06 - Oct. 31/06	42,857 Mcf	$8.73/Mcf - $12.87/Mcf	(929)
				(3,593)
Crude Oil				
Collar	Jan. 1 - Dec. 31/06	3,000 bbls	U.S. $55.00 - $75.17/bbl	443
Unrealized risk management loss				$ (3,150)

The Company has not entered into any additional contracts subsequent to December 31, 2005.

At December 31, 2004 the mark-to-market valuation of commodity contracts resulted in a $2.0 million unrealized risk management asset.

ii) DEFERRED RISK MANAGEMENT LOSS

As at January 1, 2004, the Company elected not to designate any of its risk management activities as accounting hedges and accordingly accounts for all derivative instruments using the mark-to-market method. As a result, on January 1, 2004, the Company recorded a liability and a deferred risk management loss of $10.9 million relating to then outstanding commodity hedges and the interest rate swap. During the year ended December 31, 2005, $1.6 million (2004 - $3.6 million) of the deferred loss was charged to earnings. The remaining balance of $5.6 million at December 31, 2005 (2004 - $7.3 million) relates to the interest rate swap and will be charged to earnings in annual amounts of $1.6 million until eliminated in 2009.

iii) CROSS CURRENCY INTEREST RATE SWAP

Concurrent with the closing of the 9.90% senior notes offering in 2002, the Company entered into interest rate swap arrangements with its banking syndicate that convert fixed rate U.S. dollar denominated interest obligations into floating rate Canadian dollar denominated interest obligations. This arrangement resulted in an effective interest rate of 7.63% during period ended December 31, 2005 (2004 - 7.24%, 2003 - 7.85%) net of gains realized. On purchase of the majority of the 9.90% senior notes in November 2005, the Company elected not to collapse the cross currency interest rate swap and incur the associated costs of approximately $12.2 million. Accordingly, the swap remains outstanding and at December 31, 2005, the Company valued the liability relating to future unrealized losses on the swap arrangements to be $14.8 million (2004 - $11.4 million) on a mark-to-market basis.

iv) RISK MANAGEMENT (GAINS) LOSSES

Risk management (gains) and losses recognized during the periods relating to the above are summarized below:

Years ended December 31, 2005	**Commodity Contracts**	**Interest Rate Swap**	**Total**
Unrealized			
Amortization of deferred loss	**$ –**	**$ 1,642**	**$ 1,642**
Change in fair value	**5,136**	**3,393**	**8,529**
	5,136	**5,035**	**10,171**
Realized			
Cash settlements	**9,663**	**(532)**	**9,131**
Total loss	**$ 14,799**	**$ 4,503**	**$ 19,302**

Years ended December 31, 2004	Commodity Contracts	Interest Rate Swap	Total
Unrealized			
Amortization of deferred loss	$ 2,001	$ 1,642	$ 3,643
Change in fair value	(3,986)	2,522	(1,464)
	(1,985)	4,164	2,179
Realized			
Cash settlements	9,151	(2,522)	6,629
Total loss	$ 7,166	$ 1,642	$ 8,808

Risk management loss of $4.1 million for year ended December 31, 2003 reflects realized losses recognized under hedge accounting.

b) *Other financial instruments and risk*

i) CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for oil and natural gas sales which are generally made to large credit worthy purchasers and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to financial instruments. The Company deals with major institutions and believes these risks are minimal.

ii) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Other than its senior term notes, the fair values of the Company's financial assets and liabilities that are included in the Company's consolidated balance sheet as at December 31, 2005, approximate their carrying value. The estimated fair value of senior term notes was $361.1 million as at December 31, 2005 (2004 - $218.5 million) based upon market information.

iii) FOREIGN CURRENCY RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk. During 2003, a gain of $2.5 million was realized and included in revenue. Subsequent to December 31, 2005 the Company entered into the following forward contracts:

Foreign Currency	Term	Notional Amount	Exchange Rate
Currency forward	Jan. 1 - Dec. 31/06	U.S. $55,000/day	1.1530
Currency forward	Jan. 1 - Dec. 31/06	U.S. $55,000/day	1.1630

17. CASH FLOW

Changes in non-cash working capital items increased (decreased) cash as follows:

Years ended December 31,	**2005**	2004	2003
Accounts receivable and other	**$ (17,371)**	$ (20,176)	$ (16,593)
Accounts payable	**78,385**	39,598	23,635
Taxes payable	**(301)**	(2,526)	1,541
	$ 60,713	$ 16,896	$ 8,583
Net change in non-cash working capital			
Relating to:			
Operating activities	**$ 8,441**	$ (12,594)	$ 1,318
Financing activities	**(1,829)**	324	(1,387)
Investing activities	**54,101**	29,166	8,652
	$ 60,713	$ 16,896	$ 8,583

Amounts paid during the year relating to interest expense and capital taxes were as follows:

Years ended December 31,	**2005**	2004	2003
Interest paid	**$ 31,444**	$ 28,604	$ 26,923
Current income taxes paid	**$ 4,101**	$ 4,952	$ 1,485

18. COMMITMENTS AND CONTINGENT LIABILITIES

a) Commitments

The Company has committed to certain payments over the next five years, as follows:

	2006	2007	2008	2009	2010
Operating leases	$ 11,277	$ 4,809	$ 2,609	$ –	$ –
Office rent	1,356	249	–	–	–
MPP partnership distributions	9,172	9,172	9,172	3,057	–
9.9% senior notes	–	–	–	7,870	–
Other	52	–	–	–	–
	$ 21,857	$ 14,230	$ 11,781	$ 10,927	$ –

b) Legal proceedings

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, in management's opinion, are minor in nature and are not expected to have a material impact on the financial position or results of operations of the Company.

19. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

Reconciliation of consolidated financial statements to United States generally accepted accounting principles

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Company's statements of earnings, balance sheets, and statements of cash flows, are described below.

Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP:

For the years ended December 31,	**2005**	2004	2003
Net earnings for year, as reported	**$ 81,326**	$ 63,633	$ 118,880
Adjustments			
Accounting for income taxes (Note d)	**–**	–	(743)
Risk management gain (loss), net (Note f)	**1,067**	2,236	(14,425)
Depletion and depreciation, net (Note a)	**650**	–	–
Net earnings before change in accounting principle - U.S. GAAP	**83,043**	65,869	103,712
Cumulative effect of change in accounting principle, net (Note h)	**–**	–	(5,681)
Net earnings - U.S. GAAP	**$ 83,043**	$ 65,869	$ 98,031

Consolidated Statements of Earnings - U.S. GAAP

For the years ended December 31,	**2005**	2004	2003
Revenue, net of royalties	$ **425,162**	$ 298,243	$ 263,999
Expenses			
Operating	**66,802**	55,655	49,916
Transportation	**10,858**	8,595	8,447
General and administrative	**21,223**	15,215	12,206
Interest and finance charges	**55,701**	33,733	30,595
Depletion and depreciation (Note a)	**104,525**	82,554	61,749
Foreign exchange (gain) loss	**(7,353)**	(14,631)	(47,368)
Accretion of asset retirement obligations (Note h)	**1,975**	1,670	1,436
Stock-based compensation	**5,903**	3,410	793
Guarantee (Note i)	**(375)**	–	–
Risk management loss (Note f)	**17,660**	5,165	28,428
Net earnings before taxes			
and non-controlling interest	**148,243**	106,877	117,797
Income tax expense (Note a,f)	**58,292**	37,590	14,195
Non-controlling interest (Note i)	**6,908**	3,418	(110)
Net earnings before change			
in accounting principle - U.S. GAAP	**83,043**	65,869	103,712
Cumulative effect of change			
in accounting principle, net (Note h)	**–**	–	(5,681)
Net earnings - U.S. GAAP	$ **83,043**	$ 65,869	$ 98,031
Net earnings per common share before change			
in accounting principle - U.S. GAAP			
Basic	$ **0.66**	$ 0.56	$ 0.89
Diluted	$ **0.63**	$ 0.53	$ 0.85
Net earnings per common share - U.S. GAAP			
Basic	$ **0.66**	$ 0.56	$ 0.84
Diluted	$ **0.63**	$ 0.53	$ 0.80

Statements of Other Comprehensive Income

For the years ended December 31,	**2005**	2004	2003
Net earnings for the year - U.S. GAAP	$ **83,043**	$ 65,869	$ 98,031
Accounting for hedging (Note f)	–	–	858
Comprehensive income (Note e)	$ **83,043**	$ 65,869	$ 98,889

Condensed Consolidated Balance Sheets

	2005		2004	
As at December 31	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets				
Cash	**$ 8,954**	**$ 8,954**	$ 10,068	$ 10,068
Other current assets	**132,484**	**132,484**	117,098	117,098
Property and equipment (Note a)	**1,587,371**	**1,588,350**	1,178,550	1,178,550
Goodwill	**7,914**	**7,914**	7,914	7,914
Deferred financing charges and other (Note g)	**13,156**	**10,489**	9,729	6,944
Deferred risk management loss (Note f)	**5,610**	**–**	7,252	–
	$1,755,489	**$1,748,191**	$ 1,330,611	$1,320,574
Liabilities and shareholders' equity				
Current liabilities	**$ 207,019**	**$ 207,019**	$ 345,784	$ 345,784
Long term debt (Note g)	**535,540**	**532,873**	198,594	195,809
Asset retirement obligations	**20,770**	**20,770**	18,006	18,006
Unrealized hedge loss (Note f)	**14,809**	**14,809**	11,416	11,416
Guarantee obligation (Note i)	**–**	**1,248**	–	1,623
Future income taxes (Notes a, c, f)	**312,117**	**310,182**	261,196	258,357
Non-controlling interest (Note i)	**68,898**	**67,650**	71,537	69,914
	1,159,153	**1,154,551**	906,533	900,909
Capital stock (Note d)	**226,444**	**256,431**	135,526	165,513
Contributed surplus	**9,173**	**9,173**	3,840	3,840
Retained earnings	**360,719**	**328,036**	284,712	250,312
	596,336	**593,640**	424,078	419,665
	$1,755,489	**$1,748,191**	$ 1,330,611	$1,320,574

Condensed Consolidated Statements of Cash Flows

For the years ended December 31,	**2005**	2004	2003
Operating activities			
Net earnings	**$ 83,043**	$ 65,869	$ 98,031
Amortization of deferred charges and other	**22,940**	2,101	2,208
Depletion and depreciation	**104,525**	82,554	61,749
Accretion of asset retirement obligations	**1,975**	1,670	7,117
Unrealized foreign exchange gain	**(7,808)**	(14,652)	(47,388)
Future income taxes	**53,221**	34,839	10,913
Unrealized risk management (gain) loss	**8,529**	(1,464)	24,296
Other	**11,687**	6,214	(2,033)
Change in non-cash working capital	**62,542**	20,742	20,525
Cash from operating activities	**340,654**	197,873	175,418
Cash from financing activities	**171,020**	111,179	121,443
Cash used in investing activities (Note j)	**(512,788)**	(310,362)	(285,483)
Change in cash	**(1,114)**	(1,310)	11,378
Cash, beginning of year	**10,068**	11,378	–
Cash, end of year	**$ 8,954**	$ 10,068	$ 11,378

Notes to the consolidated financial statements

a) FULL COST ACCOUNTING

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects.

Under U.S. GAAP, an impairment test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated constant dollar, future net operating revenue from proved reserves plus unimpaired unproved property costs less applicable taxes. Under Canadian GAAP, a similar impairment test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecasted pricing to determine whether impairments exist. If an impairment exists, then the amount of the write down is determined using the fair value of reserves. The Company has completed an impairment test calculation at December 31, 2005 and for all prior years, with no write-downs required under either Canadian or U.S. GAAP.

Depletion and depreciation on property and equipment is provided using the unit-of-production method under Canadian and U.S. GAAP. Both methods also use proved reserves to determine the rate however, for Canadian GAAP, proved reserves are determined using forecasted prices whereas U.S. GAAP applies constant prices. This reconciliation item resulted in a $979 thousand reduction to depletion and depreciation expense for U.S. GAAP purposes during the year ended December 31, 2005 (2004 - $nil).

b) STOCK-BASED COMPENSATION

Under Canadian GAAP, compensation costs have been recognized in the consolidated financial statements for stock options granted to employees and directors on or after January 1, 2003. For the effect on periods prior to 2003 of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 12.

c) FUTURE INCOME TAXES

Under U.S. GAAP enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the reconciliation of net earnings under Canadian GAAP to U.S. GAAP and the balance sheet effects include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The net future income tax liability is comprised of:

As at December 31	**2005**	2004
Future income tax liabilities		
Property and equipment	**$ 232,908**	$ 199,931
Timing of partnership items	**93,532**	67,089
Foreign exchange gain on long-term debt	**11,466**	10,169
Future income tax assets		
Attributed Canadian royalty income	**(8,830)**	(9,015)
Asset retirement obligations	**(6,984)**	(6,057)
Other	**(11,910)**	(3,760)
Future income taxes	**$ 310,182**	$ 258,357

d) FLOW THROUGH SHARES

U.S. GAAP requires flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred.

There have been no flow-through shares issued subsequent to 2003. The impact of recording flow-through shares at their fair value for the year ended December 31, 2003, was to increase the future income tax provision by $0.7 million and to increase capital stock by a corresponding amount.

During 2003, the Company received $4.2 million in proceeds from the issuance of flow-through shares of which $4.2 million remained unspent as at December 31, 2003. Accordingly, under U.S. GAAP, these proceeds would be disclosed separately on the balance sheet as restricted cash and would not be treated as cash or cash equivalents for statement of cash flow reporting purposes.

e) COMPREHENSIVE INCOME

Statement of Financial Accounting Standards 130, "Comprehensive Income", requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no comprehensive income other than as described under Note 19(f).

f) DERIVATIVE INSTRUMENTS AND HEDGING

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 which requires derivatives not designated as hedges to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules, any gain or loss at the implementation date is deferred and recognized into revenue once realized. At January 1, 2004, a deferred loss was recognized in the amount of $10.9 million. During the year ended December 31, 2005, $1.6 million (2004 - $3.6 million) of the deferred loss was charged to earnings. The remaining balance of $5.7 million (2004 - $7.3 million) relates to the interest rate swap and will be recognized in annual amounts of $1.6 million until eliminated in 2009. Currently, the Company has not designated any of its financial instruments as hedges for accounting purposes under U.S. or Canadian GAAP.

The deferred loss, recognized at January 1, 2004 under the Canadian GAAP transitional provision of EIC 128, has already been recognized in earnings for U.S. GAAP and became a reconciling item at December 31, 2005 and 2004.

Prior to January 1, 2004, the natural gas and crude oil futures contracts were accounted for as cash flow hedges. These contracts were recorded at fair value on the balance sheet as a $2.0 million liability at December 31, 2003. The effective portion of the change in fair value was recorded in comprehensive income, net of tax. The ineffective portion of the change in fair value was recorded in net earnings, net of tax. The effective portion of these commodity contracts was a $0.9 million gain, which was recorded in comprehensive income as at December 31, 2003. The ineffective portion of these commodity contracts was $nil which was recorded in net earnings as at December 31, 2003.

g) DEFERRED FINANCING CHARGES

Under U.S. GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred financing charges. At December 31, 2005 deferred financing charges and senior term notes were reduced by $2.7 million (2004 - $2.8 million).

h) ASSET RETIREMENT OBLIGATIONS

In 2003, the Company early adopted the Canadian Accounting Standard for asset retirement obligations, as outlined in the CICA handbook, section 3110. This standard is equivalent to U.S. SFAS 143, "Accounting for Asset Retirement Obligations", which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligations. However, a difference was created in how the transition amounts are disclosed. U.S. GAAP requires the cumulative impact of a change in an accounting principle be presented in the current year consolidated statement of earnings and prior periods not be restated. Consequently, prior year comparative periods, under U.S. GAAP, have been revised to eliminate the prior period restatement made under Canadian GAAP.

i) GUARANTEE

As discussed in Note 3 to the consolidated financial statements, MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. Only Canadian GAAP requires disclosure of this type of financial arrangement. U.S. GAAP, under FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", requires the fair valuation of the guarantee and the inclusion of the liability in the consolidated balance sheets. The offsetting adjustment is reflected as a charge to non-controlling interest. In 2005, it was determined that the offsetting adjustment, as previously disclosed as an unrealized loss on guarantee on the consolidated balance sheet was not appropriate. Accordingly, the 2004 amount has been reclassified to conform with current year presentation.

The guarantee is amortized to earnings, net of the effect on non-controlling interest, over the term of the guarantee.

j) STATEMENTS OF CASH FLOW

The consolidated statements of cash flow include under investing activities, changes in working capital for items not affecting cash, such as accounts payable and accounts receivable related to the non-cash elements of property and equipment additions. This presentation is not permitted under U.S. GAAP. The amount for the year ended December 31, 2005 of $54.1 million (2004 - $29.2 million, 2003 - $8.7 million) has been reallocated to the change in non-cash operating working capital for U.S. GAAP presentation purposes.

k) RECEIVABLE AND PAYABLE AMOUNTS

As at December 31 (in thousands of Canadian dollars)	**2005**	2004
Accounts receivable and other includes the following:		
Revenue receivable	**$ 96,026**	$ 72,510
Joint interest receivable	**26,172**	32,077
Deposits, prepaids and other	**10,286**	12,511
	$ 132,484	$ 117,098

As at December 31 (in thousands of Canadian dollars)	**2005**	2004
Accounts payable includes the following:		
Trade payables	**$ 161,607**	$ 97,608
Royalties payable	**32,001**	18,488
Other payables	**10,261**	9,387
	$ 203,869	$ 125,483

L) RECENT ACCOUNTING PRONOUNCEMENTS

In the year ended December 31, 2005, the Company adopted, for U.S. GAAP purposes, FIN 47, "Accounting for Conditional Asset Retirement Obligations" in order to address the diverse accounting practices which have developed with regard to the timing or recognition for asset retirement obligations. This interpretation did not have any impact on the consolidated financial statements as an asset retirement obligation has been provided for all the Company's long-lived assets.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have an impact on the Company:

i) As of January 1, 2006, the Company will be required to adopt, for U.S. GAAP purposes, revised SFAS 123 "Share-Based Payment". This amended statement will eliminate the alternative to use Accounting Principles Board ("APB") Opinion No. 25's intrinsic value method of accounting, as was provided in the originally issued Statement 123. As a result, public entities will be required to use the grant-date fair value of the award in measuring the cost of employee services received in exchange for an equity award of equity instruments. Compensation cost is required to be recognized over the requisite service period. Changes in fair value of liability awards during the requisite service period will be recognized as compensation cost over the vesting period. Compensation cost will not be recognized for equity instruments for which employees do not render the requisite service. Although the Company is in the process of assessing the impact of this amendment, the Company does not expect the amendments to have a material impact on its consolidated statements.

ii) As of January 1, 2006, the Company will be required to adopt, for U.S. GAAP purposes, SFAS 154 "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS 3". Change in the SFAS 154 will require retroactive application of voluntary changes in accounting principles, unless it is impracticable. The Company does not expect this standard to have a material impact on its financial statements.

SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (unaudited)

A) Net Proved Oil and Natural Gas Reserves

The net proved oil and natural gas reserve estimates as at December 31, 2005, 2004 and 2003 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale is covered by contract, in which case the applicable contract price was used. Operating costs, royalties and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

ESTIMATED QUANTITIES OF RESERVES

	2005		2004		2003	
Years ended December 31,	**Crude oil & NGL's (mbbls)**	**Natural Gas (MMcf)**	Crude oil & NGL's (mbbls)	Natural Gas (MMcf)	Crude oil & NGL's (mbbls)	Natural Gas (MMcf)
Balance, beginning of year	**18,771**	**359,975**	14,542	326,573	10,723	314,501
Revisions of previous estimates	**5,550**	**59,930**	2,797	16,547	2,297	(12,821)
Extensions, discoveries and other additions	**6,498**	**66,940**	3,026	47,713	2,869	54,128
Acquisitions of minerals in place	**723**	**5,564**	427	9,444	404	2,333
Dispositions of minerals in place	**–**	**(56)**	(440)	(3,160)	–	–
Production	**(2,026)**	**(36,850)**	(1,581)	(37,142)	(1,751)	(31,568)
Balance, end of year	**29,516**	**455,503**	18,771	359,975	14,542	326,573
Proved developed reserves						
Balance, beginning of year	**15,481**	**318,177**	10,309	288,899	9,723	293,836
Balance, end of year	**23,827**	**385,243**	15,481	318,177	10,309	288,899

B) Capitalized Costs Related to Oil and Natural Gas Activities

The aggregate capitalized costs of oil and natural gas activities and costs incurred in oil and natural gas property acquisitions, development, and exploration activities were as follows (excluding MPP and parts inventory):

CAPITALIZED COSTS

As at December 31 (in thousands of Canadian dollars)	**2005**	2004
Proved properties	**$ 1,665,455**	$1,218,826
Unproved properties:		
Acquisition	**129,490**	117,194
Exploration	**143,606**	83,238
Accumulated depletion and depreciation	**(421,510)**	(318,583)
	$ 1,517,041	$1,100,675

COSTS INCURRED ON UNPROVED PROPERTIES

As at December 31, (in thousands of Canadian dollars)	**Cumm. 2005**	Includes costs incurred in 2005	2004	2003	Prior Years
Acquisition	**$ 129,490**	$ 12,296	$ 13,217	$ 2,933	$ 101,044
Exploration	**143,606**	60,368	13,418	15,615	54,205
	$ 273,096	$ 72,664	$ 26,635	$ 18,548	$ 155,249

COSTS INCURRED

Years ended December 31 (in thousands of Canadian dollars)	**2005**	2004	2003
Acquisition costs (net of disposition)			
Proved properties	**$ 28,575**	$ 12,686	$ 11,224
Unproved properties	**12,296**	13,217	2,933
Development costs			
Development of proved undeveloped reserves	**140,504**	60,227	25,232
Other	**283,667**	136,198	115,612
Exploration costs	**46,484**	76,648	64,615
Total costs incurred	**$ 511,526**	$ 298,976	$ 219,616

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proved reserves are established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

C) *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves*

The standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions. The computation also excludes values attributable to the Company's midstream interests, referred to in the Financial Statements as MPP.

Under the Standardized Measure, future cash inflows are estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carry forwards are also considered in the future income tax calculation. Future net cash inflows after income taxes are discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Years ended December 31 (in thousands of Canadian dollars)	**2005**	2004	2003
Future cash inflows	**$ 6,571,858**	$ 3,160,270	$2,467,604
Future production costs	**(1,718,793)**	(971,392)	(785,187)
Future development costs	**(209,901)**	(102,557)	(76,708)
Future net cash flows	**4,643,164**	2,086,321	1,605,709
Income taxes	**(1,344,684)**	(539,539)	(460,291)
Total undiscounted future net cash flows	**3,298,480**	1,546,782	1,145,418
10 percent annual discount for estimated timing of cash inflows	**(1,726,975)**	(793,904)	(592,409)
Standardized measure of discounted future net cash flows	**$ 1,571,505**	$ 752,878	$ 553,009

The Company estimates that it will incur $106.8 million in 2006, $44.6 million in 2007 and $23.9 million in 2008 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the standardized measure of discounted future net cash flows from proved oil and natural gas reserves:

Years ended December 31 (in thousands of Canadian dollars)	**2005**	2004	2003
Beginning of year	**$ 752,878**	$ 553,009	$ 653,697
Sales of production, net of production costs	**(336,711)**	(226,408)	(197,323)
Net change in sales prices, net of production costs	**614,690**	42,728	(64,509)
Extensions, discoveries and additions	**354,186**	161,106	144,565
Changes in estimated future development costs	**(135,499)**	(54,838)	(39,965)
Development costs incurred during the period which reduced future development costs	**353,740**	184,053	85,586
Revisions in quantity estimates	**526,474**	306,271	(69,386)
Accretion of discount	**75,288**	75,908	101,612
Purchase of reserves	**(7,749)**	(7,749)	6,328
Sales of reserves	**87**	4,416	–
Net change in income tax	**(331,850)**	(42,270)	156,350
Changes in production rates (timing) and other	**(294,029)**	(243,348)	(223,946)
Standardized measure, end of year	**$ 1,571,505**	$ 752,878	$ 553,009

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